Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Sections 14(1), 14(2), 14(3), 14(4)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

Section 14(1)

- *Full name, mailing address, and e-mail address of applicant.*
- *A reference to the particular provision of law requiring Commission approval.*

Section 14(2)

- *If applicant is a corporation, the applicant shall identify in the application the state in which it is incorporated and the date of its incorporation, attest that it is currently in good standing in the state in which it is incorporated, and, if it is not a Kentucky corporation, state whether it is authorized to transact business in Kentucky.*

Section 14(3)

- *If applicant is a limited liability company, the applicant shall identify in the application the state in which it is organized and the date on which it was organized, attest that it is in good standing in the state in which it is organized, and, if it is not a Kentucky limited liability company, state whether it is authorized to transact business in Kentucky.*

Section 14(4)

- *If applicant is a limited partnership, a certified copy of its limited partnership agreement and all amendments, or a written statement that its partnership agreement and all amendments have been filed with the Commission in a prior proceeding and a reference to the case number of that proceeding.*

Response:

Section 14(1)
See Application Paragraph Nos. 1, 5 and 6.

Section 14(2)
See Application Paragraph No. 3 and the attached Certificates.

Section 14(3)
KU is not a limited liability company and, therefore, compliance with this filing requirement is not necessary.

Section 14(4)
KU is not a limited partnership and, therefore, compliance with this filing requirement is not necessary.

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: 206102
Visit https://app.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

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

KENTUCKY UTILITIES COMPANY

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

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

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 23rd day of August, 2018, in the 227th year of the Commonwealth.

Alison Lundergan Grimes

Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
206102/0028494

Commonwealth of Virginia

State Corporation Commission

CERTIFICATE OF GOOD STANDING

I Certify the Following from the Records of the Commission:

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

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

That the period of its duration is perpetual; and

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

Nothing more is hereby certified.

STATE CORPORATION COMMISSION
VIRGINIA
SIC SEMPER TYRANNIS
1903

Signed and Sealed at Richmond on this Date:
August 20, 2018

Joel H. Peck

Joel H. Peck, Clerk of the Commission

CISECOM
Document Control Number: 1808206394

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(1)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A statement of the reason the adjustment is required.

Response:

See Application.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(2)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

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

Response:

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

CERTIFICATE OF FICTITIOUS NAME

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

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By [signature]
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

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

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

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

[signature]
Notary Public

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

[signature]
Clerk

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

C. Gary Rakes, Clerk

Date Issued 11-26-91 [signature] Clerk or Deputy

(SEAL)

VOID IF ALTERED OR DOES NOT BEAR IMPRESSED SEAL OF COURT

VS3A - 9/03

BOOK 3, PAGE 1

CERTIFICATE OF FICTITIOUS NAME

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

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By [signature]
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

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

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

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

NOTARY PUBLIC STATE AT LARGE, KY.

[signature]
Notary Public

COMMONWEALTH OF VIRGINIA:

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

[signature]
Clerk

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

CERTIFICATE OF FICTITIOUS NAME

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

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By John T. Newton
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

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

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

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

George S. Brooks II
Notary Public

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

Lula Large, Deputy
Clerk

A COPY TESTE:
Lula Large DEPUTY CLERK

CERTIFICATE OF FICTITIOUS NAME

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

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By ______________________
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

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

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

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

NOTARY PUBLIC STATE AT LARGE

____
Notary Public

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

Charles Calton, Clerk
Clerk
By: Karen O. Jones DC.

A COPY TESTE
CHARLES CALTON, CLERK
Karen Jones
Deputy Clerk

CERTIFICATE OF FICTITIOUS NAME

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

Old Dominion Power Company

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

By ______________________
President

STATE OF KENTUCKY:

COUNTY OF FAYETTE: To-wit:

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

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

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

____
Notary Public

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

____
Clerk

A COPY TESTE
Joseph ... Gilmer, Clerk

Commonwealth of Virginia

State Corporation Commission

I Certify the Following from the Records of the Commission:

The foregoing is a true copy of an assumed or fictitious name certificate on file in the Clerk's Office of the Commission certifying that KENTUCKY UTILITIES COMPANY conducts business under the assumed or fictitious name of Old Dominion Power Company.

Nothing more is hereby certified.

STATE CORPORATION COMMISSION VIRGINIA SIC SEMPER TYRANNIS 1903

Signed and Sealed at Richmond on this Date:
August 22, 2018

Joel H. Peck

Joel H. Peck, Clerk of the Commission

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(3)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

New or revised tariff sheets, if applicable in a format that complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed.

Response:

See attached.

Kentucky Utilities Company

One Quality Street
Lexington, Kentucky
www.lge-ku.com

Rates, Terms, and Conditions for Furnishing

ELECTRIC SERVICE

In all territory served as stated on Tariff Sheet No. 1.2 of this Book

PUBLIC SERVICE COMMISSION

OF KENTUCKY

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

General Index
Rates, Terms, and Conditions T

DATE OF ISSUE: September 28, 2018

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

General Index
Rates, Terms, and Conditions T

DATE OF ISSUE: September 28, 2018

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

General Index
Territory Served

KU generates and purchases electricity, and distributes and sells electricity at retail in the following counties:

Adair	Edmonson	Jessamine	Ohio
Anderson	Estill	Knox	Oldham
Ballard	Fayette	Larue	Owen
Barren	Fleming	Laurel	Pendleton
Bath	Franklin	Lee	Pulaski
Bell	Fulton	Lincoln	Robertson
Bourbon	Gallatin	Livingston	Rockcastle
Boyle	Garrard	Lyon	Rowan
Bracken	Grant	Madison	Russell
Bullitt	Grayson	Marion	Scott
Caldwell	Green	Mason	Shelby
Campbell	Hardin	McCracken	Spencer
Carlisle	Harlan	McCreary	Taylor
Carroll	Harrison	McLean	Trimble
Casey	Hart	Mercer	Union
Christian	Henderson	Montgomery	Washington
Clark	Henry	Muhlenberg	Webster
Clay	Hickman	Nelson	Whitley
Crittenden	Hopkins	Nicholas	Woodford
Daviess			

All references hereinafter to “territory served” shall be determined by the Counties listed above.

Standard Rate **RS**

Residential Service

APPLICABLE

In all territory served.

AVAILABILITY T

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

RATE

Basic Service Charge per day:	$0.53			T/I
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	N
	$0.06318	$0.03234	$0.09552	N/I

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	D/T
Home Energy Assistance Program	Sheet No. 92	T
Franchise Fee	Sheet No. 90	T
School Tax	Sheet No. 91	T

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges. 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. T

Beginning May 1, 2019, Residential Service Customers in good standing by not having been assessed a Late Payment Charge for the previous eleven (11) months have the option of waiving one (1) late payment charge upon request. This option may only be used once every twelve (12) months as long as the Customer remains in good standing. N N N N

TERMS AND CONDITIONS

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Standard Rate **RTOD-Energy**

Residential Time-of-Day Energy Service

APPLICABLE

In the territory served.

AVAILABILITY T

Available as an option to Customers otherwise served under Rate RS. T

1. Service under this rate schedule is limited to a maximum of five hundred (500) Customers taking service on Rates RTOD-Energy and RTOD-Demand combined that are eligible for Rate RS. Company will accept Customers on a first-come-first-served basis. T
2. This service is also available to Customers on Rate GS (where the Rate GS service is used in conjunction with a Rate RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month) who demonstrate power delivered to such detached garage is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include: T T
   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 electing to take service under this rate schedule who subsequently elects to take service under Rate RS may not be allowed to return to this optional rate for twelve (12) months from the date of exiting this rate schedule. T

RATE

Basic Service Charge per day:	$0.53			T/I
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	N
Off-Peak Hours:	$0.02658	$0.03234	$0.05892	N
On-Peak Hours:	$0.28583	$0.03234	$0.31817	N/I

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	D/T
Home Energy Assistance Program	Sheet No. 92	T
Franchise Fee	Sheet No. 90	T
School Tax	Sheet No. 91	T

DATE OF ISSUE: September 28, 2018

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Standard Rate **RTOD-Energy**
Residential Time-of-Day Energy Service

RATING PERIODS T
The rating periods are established in Eastern Standard Time year-round by season for weekdays T
and weekends throughout Company's service territory, and shall be as follows: T

Summer Months of April through October

	Off-Peak	On-Peak
Weekdays	5 PM - 1 PM	1 PM - 5 PM
Weekends	All Hours	

All Other Months of November continuously through March

	Off-Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM - 11 AM
Weekends	All Hours	

If a legal holiday falls on a weekday, it will be considered a weekday. N

MINIMUM CHARGE
The Basic Service Charge shall be the Minimum Charge.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

Beginning May 1, 2019, RTOD-Energy Customers in good standing by not having been assessed N
a Late Payment Charge for the previous eleven (11) months have the option of waiving one (1) N
late payment charge upon request. This option may only be used once every twelve (12) months N
as long as the Customer remains in good standing. N

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional residential rate 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: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Standard Rate **RTOD-Demand**

Residential Time-of-Day Demand Service

APPLICABLE

In the territory served.

AVAILABILITY T

Available as an option to Customers otherwise served under Rate RS. T

1. Service under this rate schedule is limited to a maximum of five-hundred (500) Customers taking service on Rates RTOD-Demand and RTOD-Energy combined that are eligible for Rate RS. Company will accept Customers on a first-come-first-served basis. T
2. This service is also available to Customers on Standard Rate GS (where the Rate GS service is used in conjunction with a Rate RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month) who demonstrate power delivered to such detached garage is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include: T T
   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 electing to take service under this rate schedule who subsequently elects to take service under Rate RS may not be allowed to return to this optional rate for twelve (12) months from the date of exiting this rate schedule. T

RATE

Basic Service Charge per day:	$0.53			T/I
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	N
	$0.01244	$0.03234	$0.04478	N
Plus a Demand Charge per kW:				
Base Hours:	$3.44			
Peak Hours:	$8.90			I

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	D/T
Home Energy Assistance Program	Sheet No. 92	T
Franchise Fee	Sheet No. 90	T
School Tax	Sheet No. 91	T

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Standard Rate **RTOD-Demand**
Residential Time-of-Day Demand Service

RATING PERIODS T
The rating periods are established in Eastern Standard Time year-round by season for weekdays and weekends throughout Company's service territory, and shall be as follows: T T

Summer Months of April through October

	Base	Peak
Weekdays	All Hours	1 PM - 5 PM
Weekends	All Hours	

All Other Months of November continuously through March

	Base	Peak
Weekdays	All Hours	7 AM - 11 AM
Weekends	All Hours	

If a legal holiday falls on a weekday, it will be considered a weekday. N

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

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.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

Beginning May 1, 2019, RTOD-Demand Customers in good standing by not having been assessed a Late Payment Charge for the previous eleven (11) months have the option of waiving one (1) late payment charge upon request. This option may only be used once every twelve (12) months as long as the Customer remains in good standing. N N N N

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional residential rate 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.

Standard Rate **VFD**

Volunteer Fire Department Service

APPLICABLE
In all territory served.

AVAILABILITY T
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 Customer with Customer determining whether service will be provided under this schedule or any other schedule applicable to this load. 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 firefighting apparatus; and
3) half the members must be volunteers.

RATE

Basic Service Charge per day:	$0.53			T/I
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	N
	$0.06318	$0.03234	$0.09552	N/I

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

Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	D/T
Franchise Fee	Sheet No. 90	T
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 sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% 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: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Standard Rate **GS**

General Service

APPLICABLE

In all territory served.

AVAILABILITY T

To general lighting and small power loads for secondary service.

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

RATE

Basic Service Charge per day:	$1.04 single-phase service			T/I
	$1.66 three-phase service			T/I
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	N
	$0.08108	$0.03271	$0.11379	N/I

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	D/T
Franchise Fee	Sheet No. 90	T
School Tax	Sheet No. 91	

DETERMINATION OF LOAD

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.

DATE OF ISSUE: September 28, 2018

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

DETERMINATION OF MAXIMUM LOAD

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 Customer during the 15-minute period of maximum use during the month. T

MINIMUM CHARGE

The Basic Service Charge shall be the Minimum Charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% 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: September 28, 2018

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Public Service Commission in Case No.
2018-00294 dated ____

Standard Rate **AES**

All Electric School

APPLICABLE

In all territory served.

AVAILABILITY T

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

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

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

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

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

RATE

Basic Service Charge per day:	$ 2.80 single-phase service			T/I
	$ 4.60 three-phase service			T/I
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	N
	$0.05637	$0.03251	$0.08888	N/I

DATE OF ISSUE: September 28, 2018

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D/T
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 sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

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Standard Rate **PS**

Power Service

APPLICABLE

In all territory served.

AVAILABILITY T

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

RATE

	Secondary	Primary	
Basic Service Charge per day:	$2.96	$7.89	T/I
Plus an Energy Charge per kWh:	$0.03270	$0.03209	I
Plus a Demand Charge per kW:			
Summer Rate:			
(Five Billing Periods of May through September)	$23.22	$23.32	I
Winter Rate:			
(All other months)	$20.78	$20.91	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 measured load in the preceding eleven (11) monthly billing periods, or
c. if applicable, a minimum of 60% of the contract capacity based on the maximum expected load on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES

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

......	Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	T
......	Fuel Adjustment Clause	Sheet No. 85	T
	Off-System Sales Adjustment Clause	Sheet No. 88	T
	Environmental Cost Recovery Surcharge	Sheet No. 87	D/T
	Franchise Fee	Sheet No. 90	T
	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 month.

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

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than ninety (90) percent in accordance with the following formula: (based on power factor measured at the time of maximum load). T

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

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

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State Regulation and Rates
Lexington, Kentucky

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Standard Rate **TODS**

Time-of-Day Secondary Service

APPLICABLE

In all territory served.

AVAILABILITY T

Available for secondary service to Customers whose twelve (12) month-average monthly minimum loads exceed 250 kVA, and whose twelve (12) month-average monthly maximum loads do not exceed 5,000 kVA. T T T

RATE

Basic Service Charge per day:	$6.58	T/I
Plus an Energy Charge per kWh:	$0.03248	I
Plus a Maximum Load Charge per kVA:		T
Peak Demand Period:	$8.17	I
Intermediate Demand Period:	$6.47	I
Base Demand Period:	$2.65	R

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

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

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

1. the maximum measured load in the current billing period but not less than 250 kVA, or T
2. the highest measured load in the preceding eleven (11) monthly billing periods, or T
3. the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. T

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D/T
School Tax	Sheet No. 91	

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DETERMINATION OF MAXIMUM LOAD

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

D
D

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		

If a legal holiday falls on a weekday, it will be considered a weekday. N

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

Standard Rate **TODP**

Time-of-Day Primary Service

APPLICABLE

In all territory served.

AVAILABILITY T

Available for primary service to Customers whose twelve (12) month-average monthly minimum demands exceed 250 kVA, and whose new or additional load receives any required approval of Company's transmission operator. T T

RATE

Basic Service Charge per day:	$10.84	T/R
Plus an Energy Charge per kWh:	$0.03161	I
Plus a Maximum Load Charge per kVA:		
Peak Demand Period:	$7.79	I
Intermediate Demand Period:	$6.16	I
Base Demand Period:	$2.87	R

Where:

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

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

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

1. the maximum measured load in the current billing period but not less than 250 kVA, or T
2. the highest measured load in the preceding eleven (11) monthly billing periods, or T
3. the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. T

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D/T
School Tax	Sheet No. 91	

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State Regulation and Rates
Lexington, Kentucky

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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.

Customers who own and operate onsite generation of one (1) MW or larger that is not for emergency backup will be provided a 60-minute exemption from measuring load for billing purposes following a Company-system fault, but not a Company energy spike, a fault on a Customer's system, or other causes or events that result in the Customer's generation coming offline. The 60-minute exemption will begin after Company's SCADA system indicates service has been restored. T

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		

If a legal holiday falls on a weekday, it will be considered a weekday. N

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

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Standard Rate **RTS**

Retail Transmission Service

APPLICABLE

In all territory served.

AVAILABILITY T

Available for transmission service to any Customer: (1) who has a twelve (12) month-average monthly minimum demand exceeding 250 kVA; and (2) whose new or additional load receives any required approval of Company's transmission operator. T

RATE

Basic Service Charge per day:	$49.28	T/R
Plus an Energy Charge per kWh:	$0.03101	I
Plus a Maximum Load Charge per kVA:		
Peak Demand Period:	$7.59	I
Intermediate Demand Period:	$6.01	I
Base Demand Period:	$1.97	R

Where:

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

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

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

1. the maximum measured load in the current billing period but not less than 250 kVA, or T
2. the highest measured load in the preceding eleven (11) monthly billing periods, or T
3. the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. T

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D/T
School Tax	Sheet No. 91	

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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		

If a legal holiday falls on a weekday, it will be considered a weekday. N

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

Standard Rate **FLS**

Fluctuating Load Service

APPLICABLE
In all territory served.

AVAILABILITY T
Available for primary or transmission service to Customers up to an aggregate of two hundred (200) MVA for all Customers taking service under this schedule and under the Fluctuating Load Service Rate FLS schedule of Louisville Gas and Electric Company. This schedule is restricted to individual Customers whose monthly demand is twenty (20) MVA or greater. A Customer is defined as a fluctuating load if that Customer's load either increases or decreases twenty (20) MVA or more per minute or seventy (70) MVA or more in ten (10) minutes when such increases or decreases exceed one (1) occurrence per hour during any hour of the billing month.

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

BASE RATE

	Primary	Transmission	
Basic Service Charge per day:	$10.84	$49.28	T/R/R
Plus an Energy Charge per kWh:	$0.03161	$0.03101	I/I
Plus a Maximum Load Charge per kVA:			
Peak Demand Period:	$7.40	$3.88	I/I
Intermediate Demand Period:	$5.80	$2.76	I/I
Base Demand Period:	$2.68	$1.65	I

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

the monthly billing demand for the Base Demand Period is the greater of:
1. the maximum measured load in the current billing period but not less than 20,000 kVA, or T
2. the highest measured load in the preceding eleven (11) monthly billing periods, or T
3. the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. T

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Lexington, Kentucky

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ADJUSTMENT CLAUSES

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

Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90 D/T
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		

If a legal holiday falls on a weekday, it will be considered a weekday. N

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by 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. T

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 Customer exceed the limits set forth in the IEEE standards for such T characteristics. In addition, if Customer's use of Company's service under this schedule causes T 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 Customer in accordance with 807 KAR 5:006, Section 15(1)(b). T 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 Customer's expense. T

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 either Rider CSR-1 or CSR-2. Company's right to interrupt under this provision is restricted to responses to unplanned outage or de-rates of LG&E and KU Energy LLC System (LKE System) owned or purchased generation or when Automatic Reserve Sharing is invoked. LKE System, as used herein, shall consist of KU and LG&E. At Customer's request, Company shall provide documentation of the need for interruption under this provision within sixty (60) days of the end of the applicable billing period.

LIABILITY

In no event shall Company have any liability to Customer or any other party affected by the electrical T
service to Customer for any consequential, indirect, incidental, special, or punitive damages, and T
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 T
Company's service causes damage to Company's property or injuries to persons, Customer shall be T
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.

Kentucky Utilities Company

Standard Rate **LS**

Lighting Service

APPLICABLE

In all territory served.

AVAILABILITY T

Available under the conditions set out hereinafter for lighting applications such as, but not limited to, the illumination of streets, 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.

D

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).

D

RATE

Rate Code	Type of Fixture	Lumen Range	kW Per Light	Monthly Charge Fixture Only	
					T T D
Light Emitting Diode (LED)					
390	Cobra Head	6,000-8,200	0.071	$10.23	T/R
391	Cobra Head	13,000-16,500	0.122	$12.34	T/R
392	Cobra Head	22,000-29,000	0.194	$15.67	T/R
393	Open Bottom	4,500-6,000	0.048	$ 8.80	T/R
KC1	Cobra Head	2,500-4,000	0.022	$ 8.95	N
KF1	Directional (Flood)	4,500-6,000	0.030	$11.65	N
KF2	Directional (Flood)	14,000-17,500	0.096	$13.51	N
KF3	Directional (Flood)	22,000-28,000	0.175	$15.96	N
KF4	Directional (Flood)	35,000-50,000	0.297	$22.87	N

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UNDERGROUND SERVICE T/D

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

RATE D

Rate Code	**Type of Fixture**	**Lumen Range**	**kW Per Light**	**Fixture Charge**	N
Light Emitting Diode (LED)					
KC2	Cobra Head	2,500-4,000	0.022	$ 4.13	N
396	Cobra Head	6,000-8,200	0.071	$ 5.40	T/R
397	Cobra Head	13,000-16,500	0.122	$ 7.52	T/R
398	Cobra Head	22,000-29,000	0.194	$10.85	T/R
399	Colonial, 4-Sided	4,000-7,000	0.044	$ 7.65	T/R
KA1	Acorn	4,000-7,000	0.040	$ 9.12	N
KN1	Contemporary	4,000-7,000	0.057	$ 7.09	N
KN2	Contemporary	8,000-11,000	0.087	$ 8.25	N
KN3	Contemporary	13,500-16,500	0.143	$10.03	N
KN4	Contemporary	21,000-28,000	0.220	$14.55	N
KN5	Contemporary	45,000-50,000	0.380	$21.95	N
KF5	Directional (Flood)	4,500-6,000	0.030	$ 8.45	N
KF6	Directional (Flood)	14,000-17,500	0.096	$10.31	N
KF7	Directional (Flood)	22,000-28,000	0.175	$12.75	N
KF8	Directional (Flood)	35,000-50,000	0.297	$19.67	N

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RATE (continued) T

Rate Code	Type of Fixture	Lumen Range	kW Per Light	Monthly Charge	
					T
					T
High Pressure Sodium					
414	Victorian*	5,800	0.083	$36.75	I
415	Victorian*	9,500	0.117	$36.98	I

Colonial and Acorn "Post Top" lights must include one of two pole options, a Decorative Smooth pole or a Historic Fluted pole. Underground fed Cobra and Contemporary LEDs must include a Cobra pole charge or Contemporary pole charge, respectively. The Underground fed Directional (Flood) LEDs must include a Cobra or Contemporary pole charge. N

Pole Charges

Rate Code	Pole Type	Monthly Pole Charge
PK1	Cobra	$12.49
PK2	Contemporary	$12.00
PK3	Post Top – Decorative Smooth	$ 8.25
PK4	Post Top – Historic Fluted	$15.48

CONVERSION FEE

Customer will be required to pay a monthly conversion fee for 60 months if Customer requests to change current functioning non-LED fixture to an LED fixture. This conversion fee represents the remaining book value of the current working non-LED fixture.

Conversion Fee: $6.12 per month for 60 months

DUE DATE OF BILL T

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) 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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	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 (5) 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. T

TERMS AND CONDITIONS

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

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

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

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

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

DATE OF ISSUE: September 28, 2018

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

T

TERMS AND CONDITIONS (continued)

6. If Customer requests the removal of an existing lighting system, including, but not limited to, fixtures, poles, or other supporting facilities, Customer agrees to pay to Company its cost of labor to remove existing facilities. Customer will be required to pay Conversion Fee if Customer requests installation of LED replacement within five (5) years.

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.

N

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

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

Kentucky Utilities Company

Standard Rate **RLS**

Restricted Lighting Service

APPLICABLE

In all territory served.

AVAILABILITY T

Availability is restricted to those lighting fixtures/poles in service as of January 1, 2013, except where a spot replacement maintains the continuity of multiple fixtures/poles in a neighborhood lighting system or continuity is desired for a subdivision being developed in phases. 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. Spot replacements will not be available for Mercury Vapor and Incandescent rate codes. T 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.

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 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). D

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Fixture and Pole	
High Pressure Sodium						
461/471	Cobra Head	4,000	0.060	$ 9.67	$ 13.23	T/I/I
462/472	Cobra Head	5,800	0.083	10.82	14.75	N/I/I
463/473	Cobra Head	9,500	0.117	11.23	15.38	N/I/I
464/474	Cobra Head	22,000*	0.242	17.43	21.88	N/I/I
465/475	Cobra Head	50,000*	0.471	27.58	30.55	N/I/I
409	Cobra Head	50,000	0.471	15.22		T/I
426	Open Bottom	5,800	0.083	9.40		T/I
428	Open Bottom	9,500	0.117	9.65		N/I
487	Directional (Flood)	9,500	0.117	11.06		N/I
488	Directional (Flood)	22,000*	0.242	16.73		N/I
489	Directional (Flood)	50,000*	0.471	23.66		N/I

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State Regulation and Rates
Lexington, Kentucky

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OVERHEAD SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Fixture and Pole	T
Metal Halide						N
450/454	Directional (Flood)	12,000*	0.150	$17.64	$22.74	N/I/I
455	Directional (Flood)	32,000*	0.350		29.80	N/I/I
452/459	Directional (Flood)	107,800*	1.080	51.50	56.59	N/I/I
451	Directional (Flood)	32,000*	0.350	24.71		N/I
Mercury Vapor						N
446/456	Cobra Head	7,000	0.207	$11.71	$14.38	N/I/I
447/457	Cobra Head	10,000	0.294	13.82	16.19	N/I/I
448/458	Cobra Head	20,000	0.453	15.59	18.25	N/I/I
404	Open Bottom	7,000	0.207	12.81		N/I
Incandescent						
421	Tear Drop	1,000	0.102	$ 4.09		I
422	Tear Drop	2,500	0.201	5.41		I
424	Tear Drop	4,000	0.327	8.03		I
425	Tear Drop	6,000	0.447	10.74		I

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

UNDERGROUND SERVICE

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

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Pole Type	Monthly Charge	T
Metal Halide						
460	Directional (Flood)	12,000	0.150	Decorative Smooth	$33.81	T/I
469	Directional (Flood)	32,000	0.350	Decorative Smooth	39.91	T/I
470	Directional (Flood)	107,800*	1.080	Decorative Smooth	66.45	T/I

UNDERGROUND SERVICE (**continued**)
RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Pole Type	Monthly Charge	T T
Metal Halide (continued)						
490	Contemporary	12,000*	0.150	Fixture Only	$19.05	I
491	Contemporary	32,000*	0.350	Fixture Only	$26.72	N/I
493	Contemporary	107,800*	1.080	Fixture Only	$55.38	I
494	Contemporary	12,000*	0.150	Decorative Smooth	$34.01	I
495	Contemporary	32,000*	0.350	Contemporary	$41.92	N/I
496	Contemporary	107,800*	1.080	Decorative Smooth	$70.33	I
High Pressure Sodium						
440	Acorn	4,000	0.060	Decorative Smooth	$17.02	I
410	Acorn	4,000	0.060	Historic Fluted	$24.98	I
401	Acorn	5,800	0.083	Decorative Smooth	$18.67	N/I
411	Acorn	5,800	0.117	Historic Fluted	$26.52	N/I
420	Acorn	9,500	0.083	Historic Fluted	$19.05	N/I
430	Acorn	9,500	0.117	Historic Fluted	$27.04	N/I
466	Colonial	4,000	0.060	Decorative Smooth	$12.18	I
412	Coach	5,800	0.083	Decorative Smooth	$36.74	I
413	Coach	9,500	0.117	Decorative Smooth	$36.99	I
467	Colonial	5,800	0.083	Decorative Smooth	$13.75	N/I
468	Colonial	9,500	0.117	Decorative Smooth	$14.00	
492	Contemporary	5,800	0.083	Fixture Only	$18.59	
476	Contemporary	5,800	0.083	Contemporary	$20.99	
497	Contemporary	9,500	0.117	Fixture Only	$18.36	
477	Contemporary	9,500	0.117	Contemporary	$25.80	
498	Contemporary	22,000*	0.242	Fixture Only	$21.46	
478	Contemporary	22,000*	0.242	Contemporary	$33.25	
499	Contemporary	50,000*	0.471	Fixture Only	$26.01	
479	Contemporary	50,000*	0.471	Contemporary	$40.97	
300	Dark Sky	4,000	0.060	Decorative Smooth	$26.83	
301	Dark Sky	9,500	0.117	Decorative Smooth	$27.98	

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DUE DATE OF BILL

Payment is due within sixteen (16) business days (no less than twenty-two (22) 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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	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 (5) 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.

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Standard Rate **LE**

Lighting Energy Service

APPLICABLE

In all territory served.

AVAILABILITY T

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

$0.07264 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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D/T
School Tax	Sheet No. 91	

DUE DATE OF BILL

Customer’s payment will be due within sixteen (16) business days (no less than twenty-two (22) 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.

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State Regulation and Rates
Lexington, Kentucky

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Standard Rate **TE**

Traffic Energy Service

APPLICABLE

In all territory served.

AVAILABILITY T

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, but not limited to, signals, cameras, or other traffic lights, electronic communication devices, emergency sirens, and gunshot triangulation N
devices. N

RATE

Basic Service Charge per day:	$0.13 per delivery point	T/R
Plus an Energy Charge per kWh:	$0.08955	

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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D/T
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 sixteen (16) business days (no less than twenty-two (22) 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.

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CONDITIONS OF SERVICE (continued)

2. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and Customer. Where attachment of Customer's devices is made to Company facilities, Customer must have an attachment agreement with Company. T

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.

Pole and Structure Attachment Charges

APPLICABLE

In all territory served.

AVAILABILITY

Available to the facilities of Governmental units, Educational Institutions, Cable Television System Operators and Telecommunications Carriers as provided below except: (1) facilities of local exchange carriers ("ILECs") with joint use agreements with Company; (2) facilities subject to a fiber exchange agreement; and (3) Macro Cell Facilities. Nothing in this tariff expands the right to attach to Company's structures beyond the rights otherwise conveyed by law.

APPLICABILITY OF SCHEDULE TO CURRENT LICENSE AGREEMENTS

Any Telecommunications Carrier that executed a license agreement permitting attachments to Company's Structures prior to the July 1, 2017 shall be subject to the rates, terms, and conditions of this Pole and Structure Attachment Charges Schedule ("this Schedule") upon expiration or termination of its license agreement. Any Governmental Unit or Educational Institution that executed a license agreement permitting attachments to Company's Structures prior to May 1, 2019 shall be subject to the rates, terms and conditions of this Schedule upon expiration or termination of its license agreement, unless such license agreement provides otherwise.

DEFINITIONS

"Affiliate" means, with respect to an entity, any entity controlling, controlled by, or under common control with such entity.

"Approved Contractor" means a contractor approved by Company for a particular purpose.

"Attachment" means the Cable or Wireless Facilities and all associated appliances including without limitation any overlashed cable, guying, small splice panels and vertical overhead to underground risers but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or otherwise conflicts with Company's electric design and construction standards.

"Attachment Customer" means a Customer that attaches its facilities to one or more of Company's Structures and has executed a Contract for Attachment to Company Structures with Company.

"Contract for Attachment to Company Structures" or "Contract" means the written agreement provided by Company and executed between Attachment Customer and Company incorporating the terms and conditions of this Schedule.

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"Business Day" means a calendar day unless it is a Saturday, a Sunday or a legal holiday.

"Cable" means the fiber optic or coaxial cable, or any other type of cable, as well as any messenger wire or support strand.

"Cable Television System Operator" means a Person who operates a system that transmits television signals, for distribution to subscribers of its services for a fee, by means of wires or cables connecting its distribution facilities with its subscriber's television receiver or other equipment connecting to the subscriber's television receiver, and not by transmission of television signals through the air, and subscription to the system's service is available to the public.

"Communication Space" means the area below the Communication Worker Safety Zone to the limit of allowable NESC clearance, department of transportation or other governmental requirements, and Company's internal construction standards on poles.

"Communication Worker Safety Zone" means the space between the facilities located in the Supply Space and facilities located in the Communications Space on poles.

"Contractor" means any Person employed or engaged by Attachment Customer to perform work or render services upon or in the immediate vicinity of Company's Structures or associated facilities other than Attachment Customer and Attachment Customer's employees.

"Credit Rating" means, with respect to any entity, the rating then assigned to such entity's unsecured, senior long-term debt obligations (not supported by third party credit enhancements) by Standard and Poor's Rating Group or its successor ("S&P"), or Moody's Investor Services, Inc. or its successor ("Moody's"), or if such entity does not have a rating for its senior unsecured long-term debt, then the rating then assigned to such entity as its "corporate credit rating" assigned by S&P, or the "long-term issuer rating" assigned by Moody's.

"Distribution Pole" means a utility pole supporting electric supply facilities, all of which operate at less than 69 kV, but does not include a non-wood street light pole or a wood street light pole that is not located in a public right-of-way.

"Duct" means a pipe, tube, conduit, manhole, or other structure made for supporting and protecting electric and/or communications wires or cables and in which wires, cables and conduits may be placed for support or protection but excluding (1) any pipe now or previously used for the transmission or distribution of natural gas, (2) any duct system supporting electric supply lines operated at 69kV or greater, and (3) any vault.

"Educational Institution" means a public or private, non-profit university, college or community college

"Governmental Unit" means an agency or department of the Federal Government, a department, agency, or other unit of the Commonwealth of Kentucky, a county or city, special district, or other political subdivision of the Commonwealth of Kentucky.

"High Volume Application" means an application or applications for Attachments to more than 300 poles or to place Cable or conduit through more than 10 manholes submitted to Company within a thirty (30) day period.

"Letter(s) of Credit means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch in a form acceptable to the Company. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit.

"Macro Cell Facility" means a wireless communications system site that is typically high-power and high-sited, and capable of covering a large physical area, as distinguished from a distributed antenna system (DAS), small cell, or WiFi attachment, by way of example. Macro Cell Facilities are typically, but not exclusively, co-located on Transmission Poles and communications monopoles and towers.

"Make-Ready Survey" means a survey, in the form prescribed by Company from time to time, prepared by Company or an Approved Contractor describing in reasonable detail the make-ready engineering requirements, and such other information as Company may require, for the installation of an Attachment or group of Attachments on a Structure or group of Structures.

"NEC" means the National Electrical Code.

"NESC" means the National Electrical Safety Code.

"Performance Assurance" means collateral in the form of cash, surety bond, Letter(s) of Credit, or other security acceptable to the Company.

"Person" is defined by KRS 278.010(2).

"Service Drop" means a Cable, attached to a pole with a J-hook or other similar hardware that connects the trunk line to an end user's premises.

"Structure" means any Company pole, conduit, duct, or other facility normally used by Company to support or protect its electric conductors but shall not include (1) any Transmission Pole with electric supply lines operated at 138kV or above; (2) any Transmission Pole with electric supply lines operated at less than 138kV other than Transmission Poles to which Company has also attached electric supply lines operated at less than 69kV; (3) any street light pole that is not a wood pole located in a public right-of-way; or (4) any pole that Company has leased to a third party.

"Supply Space" means the space above the Communications Worker Safety Zone used for the installation of electric supply lines.

"Telecommunications carrier" means a Person who operates a system that (1) transmits by wire or wireless means, between or among points specified by the user, information of the user's choosing without change in the form or content of the information as sent or received, and (2) provides such transmission services for a fee directly to or for the public, or to such classes of users as to be effectively available directly to or for the public.

"Transmission Pole" means any utility pole or tower supporting electric supply facilities designed to operate at 69 kV or greater.

"Wireless Facility" means, without limitation, antennas, risers, transmitters, receivers, and all other associated equipment used in connection with Attachment Customer's provision of wireless communications services and the transmission and reception of radiofrequency signals, but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or that conflicts with Company's electric design and construction standards.

ATTACHMENT CHARGES

$ 7.25 per year for each wireline pole attachment.
$ 0.81 per year for each linear foot of duct.
$36.25 per year for each Wireless Facility located on the top of a Company pole.

The attachment charge for any other Wireless Facility shall be agreed upon by Attachment Customer and Company and set forth in a special contract to be filed with the Commission.

BILLING

All attachment charges for use of Structures will be billed semi-annually based upon the type and number of Attachment Customer's Attachments reflected in Company's records on December 1 and June 1. A bill issued under this Schedule shall be due upon its issuance. Any bill not paid in full within sixty (60) days of its issuance shall be assessed a late payment charge of three (3) percent on the bill's current charges. If Attachment Customer fails to pay all charges and fees billed within six (6) months of the bill's issuance, Company may remove any or all of Attachment Customer's Attachments. In lieu of or in addition to removal of Attachments, Company may exercise any other remedies available under law to address Attachment Customer's failure to make timely payment of any charges assessed under this Schedule.

TERM OF SERVICE

An executed Contract shall be for a term of 10 (ten) years and shall thereafter automatically renew for successive one (1) year periods unless Company or Attachment Customer provides the other with written notice of termination at least sixty (60) days prior to the renewal date.

TERMS AND CONDITIONS OF ATTACHMENT

Attachments to Company's Structures that do not interfere with Company's electric service requirements and the Attachments of existing Customers and joint users shall be permitted in accordance with the terms and conditions of this Schedule. The Terms and Conditions set forth in Section 5 of the Company's Electric Service Tariff shall also be applicable to the extent they are not in conflict with or inconsistent with this Schedule's provisions.

1. **CONTRACT FOR ATTACHMENT TO COMPANY STRUCTURES**

   No Attachments shall be made to Company's Structures until Attachment Customer has executed a Contract for Attachment to Company Structures, in a form substantially similar to that which is included at the end of this Schedule.. The Contract shall incorporate the terms and conditions set forth in this Schedule.

2. **NO PROPERTY RIGHTS**

   No use, however extended, of Company Structures shall create or vest in Attachment Customer any right, title or interest in the Structures. A Contract confers only a non-exclusive right to affix and install Attachments to and on Company's Structures. Company is not required to maintain any Structure for a period longer than demanded by its electric service requirements.

3. **USE OF COMPANY'S FACILITIES BY OTHERS**

   Nothing in this Schedule shall affect the rights or privileges previously conferred by Company to others. The rights granted under this Schedule and the Contract shall at all times be subject to such previously conferred privileges and shall not affect the rights or privileges that may be conferred by Company in the future to others.

4. **TRANSFER OF RIGHTS**

   Except as provided in this Schedule, Attachment Customer's rights under the Contract are non-delegable, non-transferable and non-assignable. Any delegation, transfer or assignment of any interest created by the Contract or this Schedule without Company's prior written consent is voidable at Company's option. Company shall not unreasonably withhold its consent to Attachment Customer's delegation, transfer or assignment of rights under the Contract upon notice of the delegation, transfer or assignment and if adequate evidence is provided of transferee's compliance with Term 23 (Insurance) and Term 24 (Performance Assurance).

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Attachment Customer shall not permit a third party to overlash or utilize any Attachment without Company's prior written consent. Company may condition its consent upon such third party's compliance with all provisions of the Contract, this Schedule, and such other terms as Company may reasonably require.

5. COMPANY'S ABANDONMENT OF STRUCTURE

Company shall provide an Attachment Customer with a minimum of 180 days' notice before abandoning a Structure to which Attachment Customer has made an Attachment unless state or local law, easement provisions, or contractual obligations to a third party requires the Structure to be abandoned in a shorter period, in which case Company shall provide as much notice as is reasonably practicable.

6. FRANCHISES AND EASEMENTS

Attachment Customer shall secure at its own expense any right-of-way, easement, license, franchise or permit from any Person that may be required for the construction or maintenance of Attachments by or for Attachment Customer. If requested by Company, Attachment Customer shall submit to Company satisfactory evidence of such right-of-way, easement, license, franchise or permit. Company's approval of Attachments shall not constitute any representation or warranty regarding Attachment Customer's right to occupy or use any public or private right-of-way.

Upon an Attachment Customer's written request, Company may provide to Attachment Customer such non-private information as Company may have regarding the name of the record landowners from which Company obtained easements for Structures. Such information is provided without representation or warranty as to its accuracy or completeness. Company has no obligation to correct or supplement any information so provided. If Company provides assistance to Attachment Customer in obtaining easements or other property rights, Attachment Customer shall reimburse Company's cost of providing such assistance within thirty (30) days of its receipt of an invoice from Company.

Attachment Customer shall indemnify and save harmless Company from all claims, including the expenses incurred by Company to defend itself against such claims, resulting from or arising out of the failure of Attachment Customer to secure any right of way, easement, license, franchise or permit.

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7. ATTACHMENT APPLICATIONS AND PERMITS

a. Unless waived by Company, Attachment Customer shall make written application, in the form and manner prescribed by Company for permission to install Attachments on or in any Structure. Each application shall include: (1) in the case of poles, the owner, number and location of all Structures for which license to attach is sought and the amount of space required thereon; (2) in the case of Ducts, the number of linear feet of Duct space and the specific location of each such Duct to be utilized, the amount of requested space, the nature of any changes or inner Duct or Ducts proposed to be installed and any other construction that might be required by the proposed Attachments; (3) the physical attributes of all proposed Attachments; (4) the proposed start date for installation of the Attachments; (5) any issues then known to Attachment Customer regarding space, engineering, access or other matters that might require resolution before installation of Attachments; and (6) proposed make ready drawings. Company may request additional information be included with the application at its reasonable discretion. Company may perform a pole loading study or request Attachment Customer to submit such study based upon a visual inspection or other information held by Company. If Company conducts a visual inspection of the pole to ascertain the need for a pole loading analysis, Company may assess the cost of such inspection to the Attachment Customer. If Company determines a pole loading study is required, no application shall be considered completed until submission of such study. Attachment Customer may perform the pole loading study or request Company to perform the study with cost to be borne by Attachment Customer. Nothing contained herein shall preclude Attachment Customer from submitting a pole loading study with its application without Company performing a visual inspection or otherwise requesting such study to expedite Company's review.

b. Attachment Customer shall be responsible for all costs associated with the application, a Make Ready Survey, engineering analysis, and Company's review of the application. Attachment Customer shall reimburse Company upon presentation of an invoice for such costs. If Attachment Customer does not request Attachments to a Transmission Pole or Duct, Company shall complete a Make Ready Survey within sixty (60) days of its receipt of Attachment Customer's completed application. If Attachment Customer's application requests Attachments to a Transmission Pole or Duct, Attachment Customer and Company shall mutually agree to a time period for completion of a Make-Ready Survey.

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c. Upon completion of the Make Ready Survey, Company shall notify Attachment Customer in writing whether its application for use of Company's Structures has been granted, of any necessary changes to the proposed construction drawings, and the conditions, if any, imposed on the installation or use of Attachments. Company reserves the right to deny access to any Structure based upon lack of capacity, safety, reliability or engineering standards. Company may deny access to Transmission Poles in its discretion for any reason; provided that such denials shall be determined in a non-discriminatory manner. The following types of Transmission Poles that do not support electric supply lines operated at less than 69kV are not available for Attachments under this Schedule: (1) Transmission Poles that do not support electric supply lines operated at less than 69kV; (2) any Transmission Poles that support electric supply lines operated at 138kV or above.

d. Within fifteen (15) days of notifying Attachment Customer of the approval of its application, Company shall provide Attachment Customer a written statement of the costs of any necessary Company make-ready work, including but not limited to rearrangement of electric supply facilities and pole change out. Attachment Customer shall indicate its approval of this statement by submitting payment of the statement amount within fifteen (15) days of receipt. If facilities of a third party are required to be rearranged or transferred, Attachment Customer shall coordinate with the third party for such rearrangement or transfer and shall pay the costs related thereto. If Attachment Customer's application requests attachments to a Transmission Pole or Duct, Attachment Customer and Company shall mutually agree to a time period for preparation of a written statement of the costs of any necessary Company make-ready work.

e. If an existing Structure is replaced or a new Structure is erected solely to provide adequate capacity for Attachment Customer's proposed Attachments, Attachment Customer shall pay a sum equal to the actual material and labor cost of the new Structure, as well as any replaced appurtenances, plus the cost of removal of the existing Structure minus its salvage value, within thirty (30) days of receipt of an invoice. The new Structure shall be Company's property regardless of any Attachment Customer payments toward its cost. Attachment Customer shall acquire no right, title or interest in or to such Structure.

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f. If Company is unable to perform the Make Ready Survey and engineering analysis within the time period established under Section 7b, Company shall advise Attachment Customer and promptly meet with Attachment Customer to develop a mutually agreeable plan of performance.

g. If Company fails to perform the make-ready work within sixty (60) days of receipt of Attachment Customer's payment of the make-ready costs, Attachment Customer may perform such work at its expense using an Approved Contractor, except that Attachment Customer may not perform such work with respect to Transmission Poles or Ducts.. The Approved Contractor shall provide notice to Company at least one week prior to performing any make-ready. During the performance of any make-ready by Approved Contractors, an inspector designated by Company shall accompany the Approved Contractor(s). The inspector, in his or her sole discretion, may direct that work be performed in a manner other than as approved in an application, based on the then-existing circumstances in the field. The cost of such inspector(s) shall be reimbursed by Attachment Customer within 30 days of receipt of an invoice from Company. Company shall refund any unexpended make-ready fees within 30 days of notice that Attachment Customer has performed the work.

h. If Attachment Customer submits to Company within a thirty (30) day period an application or applications for Attachments to more than 300 poles or to place Cable or conduit through more than ten (10) manholes, such application or applications shall be considered a High Volume Application. The provisions set forth in Sections 7b through 7g that relate to time period and cost-reimbursement of Company's performance of application review, engineering analysis, and a Make Ready Survey, and the performance of make-ready work, shall not apply to High Volume Applications. Company and Attachment Customer submitting a High Volume Application shall develop a mutually agreeable plan of performance and cost reimbursement for Company's performance of application review, engineering analysis, and a Make Ready Survey, and the performance of make ready work, shall set this plan to writing and shall file it with the Commission as a special contract.

i. No written application to Company to affix and attach a Service Drop to Company's poles is required but Attachment Customer shall provide notice to Company within sixty (60) days of attachment of such Service Drop. This notice shall include the Service Drop location address (or a description of the location if the address is not available), the date of the attachment, the pole number of the pole to which the Service Drop is affixed or attached, and a statement as to whether the Service Drop constitutes a new Attachment to Company's pole for billing purposes. Any Service Drop affixed to a pole more than six (6) inches above or below a through-bolt shall be considered a separate Attachment for billing purposes. On drop or lift poles only, all Service Drops affixed within one foot of usable space shall be considered a single Attachment for billing purposes. Company may conduct an inspection of any Service Drop Attachments, and Attachment Customer shall reimburse Company within 30 days of presentation of an invoice for such inspections. The provisions of this Pole Structure Attachment Schedule shall not apply to an ILEC service drop if the ILEC has a joint use agreement with the Company and the service drop is located in the area covered by the joint use agreement.

8. CONSTRUCTION AND MAINTENANCE REQUIREMENTS AND SPECIFICATIONS

a. Attachment Customer shall not construct or install any Attachments until : (1) Company has approved in writing the design, construction, and installation practices for Attachment Customer's Attachments; (2) all Company make-ready work, if any, has been completed (and, if such make-ready work has been performed by an Approved Contractor pursuant to Section 7g above, inspected by Company); and (3) any necessary third party rearrangements or transfers have been completed. Any Attachment that fails to comply with this provision shall be deemed an Unauthorized Attachment for purposes of Section 19 of this Schedule

b. All Attachments shall be constructed and installed in a manner reasonably satisfactory to Company and so as not to interfere with Company's present or future use of its Structures. Attachments in Ducts shall not include any splice enclosures or excess cable. Attachment Customer shall maintain, operate and construct all Attachments in such manner as to ensure Company's full and free access to all Company facilities. All Attachments shall conform to Company's electric design and construction standards and applicable requirements of the NESC, NEC, and all other applicable codes and laws. In the event of a conflict, the more stringent standard shall apply.

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c. Attachment Customer shall identify each of its Attachments with a tag, approved in advance by Company, that includes Attachment Customer's name, 24-hour contact telephone number, and such other information as Company may require. All Cable placed by Attachment Customer within a Company-owned or controlled Duct shall be enclosed within Attachment Customer furnished inner-duct and shall be clearly marked and identified as belonging to Attachment Customer at all access points. Service drops do not need to be tagged. Attachment Customer shall tag an Attachment at the time of construction. Any untagged Attachment existing as of the date of execution of the Contract or the effective date of this Schedule, whichever is earlier, shall be tagged by Attachment Customer when Attachment Customer or its agents perform work on the Attachment. . If the Company is required to relocate or remove an Attachment or otherwise contact the owner of an Attachment to effect repairs and the Attachment is untagged and cannot be readily identified, any expense incurred by Company to identify the Attachment owner shall be borne by the Attachment Customer. Further, the Company shall be considered to have provided notice to the owner of an untagged Attachment required under Section 16 of this Schedule upon inspecting the Attachment and determining that it is untagged.

d. In the design, installation and maintenance of its Attachments, Attachment Customer shall comply with all Company standards and all federal, state and local government laws, rules, regulations, ordinances, or other lawful directives applicable to the work of constructing and installing the Attachments. All work shall be performed in accordance with the applicable standards of the NESC and the NEC, including amendments thereto adopted. Attachment Customer shall take all necessary precautions, by the installation of protective equipment or other means, to protect all Persons and property of all kinds against injury or damage caused by or occurring by reason of the construction, installation or existence of Attachments.

e. Attachment Customer shall immediately report to Company (1) any damage caused to property of Company or others when installing or maintaining Attachments, (2) any Attachment Customer's failure to meet the requirements set forth in this Schedule for assuring the safety of Persons and property and compliance with laws and regulations of public authorities and standard-setting bodies, and (3) any unsafe condition relating to Company's Structures identified by Attachment Customer.

f. Attachment Customer shall complete installation of its Attachments within sixty (60) days of the later of approval of the application for such Attachments or, if make-ready work is required under such approval, completion of make-ready work, and shall notify Company in writing upon its completion. If Attachment Customer fails to complete the installation within this time period, Company may revoke its permit for the Attachment. Prior to revoking the permit for the Attachment, Company shall provide written notice of the revocation to Attachment Customer. Company may conduct a post-construction inspection of such Attachments. Attachment Customer shall reimburse Company within thirty (30) days of presentation of an invoice for such inspections.

g. Attachment Customer may use qualified contractors of its own choice to perform work below the Communication Worker Safety Zone. For any work in or above the Communication Worker Safety Zone that Company allows Attachment Customer to perform, Attachment Customer shall use an Approved Contractor who may, at Company's discretion, be required to be accompanied by a Company-designated inspector. For any work in Company's Ducts, Attachment Customer shall use an Approved Contractor, who must be accompanied by a Company-designated inspector. Company shall schedule a Company-designated inspector to accompany an Approved Contractor within fifteen (15) days of its receipt of such request for such inspector. Attachment Customer shall reimburse Company for the actual cost associated with providing inspection services within 30 days of receipt of an invoice.

h. Company may also monitor Attachment Customer's construction and installation of Attachments below the Communication Worker Safety Zone. If the need for a monitor is caused by Attachment Customer's failure to comply with the terms of this Schedule, the Contract, or any applicable law or regulation, Attachment Customer shall reimburse Company for the actual cost of any such monitoring within thirty (30) days of receipt of an invoice for such cost. For locations where Attachment Customer's construction and installation are within Company underground facilities, Attachment Customer shall reimburse Company for the actual cost associated with providing inspection services within thirty (30) days of receipt of an invoice.

i. Attachment Customer shall comply with all applicable federal, state, and local laws, rules and regulations with respect to environmental practices undertaken pursuant to the construction, installation, operation and maintenance of its Attachments. Attachment Customer shall not bring, store or utilize any hazardous materials on any Company site without Company's prior express written consent. To the extent reasonably practicable, Attachment Customer shall restore any property altered pursuant to this Schedule or the Contract to its condition existing immediately prior to the alteration. Company has no obligation to correct or restore any property altered by Attachment Customer and bears no responsibility for Attachment Customer's compliance with applicable environmental regulations.

j. If Attachment Customer fails to install any Attachment in accordance with the standards and terms set forth in this Schedule and Company provides written notice to Attachment Customer of such failure, Attachment Customer, at its own expense, shall make necessary adjustments within thirty (30) days of receipt of such notice. Subject to Section 15 of this Schedule, if Attachment Customer fails to make such adjustments within such time period, Company may make the repairs or adjustments, and Attachment Customer shall pay Company for the actual cost thereof plus a penalty of 50% of actual costs within thirty (30) days of receipt of an invoice.

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k. Attachment Customer is responsible for any damage, fines or penalties resulting from any noncompliance with the construction and maintenance requirements and specifications set forth in this Section 8, except when Attachment Customer demonstrates that noncompliance is due to the actions of Company or another Attachment Customer. Company undertakes no duty to require any specific action by Attachment Customer and assumes no responsibility by requiring such compliance or by requiring Attachment Customer to meet any specifications or to make any corrections, modifications, additions or deletions to any work or planned work by Attachment Customer.

l. Within fifteen (15) days of completion of the installation of the Attachment, Attachment Customer shall furnish Company with complete "as-built" drawings in a computer generated electronic format (or such other format as is agreeable to Company). Hand drawings shall not be submitted.

9. ADDITIONAL REQUIREMENTS FOR WIRELESS FACILITIES

a. Wireless Facilities Attachments may be attached to Distribution Poles only.

b. Company may require Attachment Customer to furnish with any written application for permission to install a Wireless Facilities Attachment a mock-up of the proposed Attachment.

c. Attachment Customer is solely responsible for ensuring that the radiofrequency ("RF") radiation emitted by its Wireless Facilities, alone and/or in combination with any and all sources of RF radiation in the vicinity, is within the limits permitted under all applicable governmental and industry standard safety codes for general population/uncontrolled exposure. Attachment Customer shall install appropriate signage on the poles to which Wireless Facilities have been attached, to warn line workers or the general public of the presence of RF radiation and the need for precautionary measures. Attachment Customer shall periodically inspect the signage and replace the signage if necessary to ensure that the signage, including text and warning symbols, remains clearly visible.

d. Each Wireless Facility installation shall include a switch that operates to disconnect and de-energize the antenna. In non-emergency circumstances, Company employees or contractors will make reasonable efforts to contact Attachment Customer at a telephone number that Attachment Customer has marked on the Wireless Facility installation to request a temporary power shut-down. Company personnel or those of other entities working on the pole will operate the power disconnect switch to ensure that the antenna is not energized while work on the pole is in progress. In emergency circumstances, Company personnel and those of other entities working on Company poles may accomplish the power-down by operation of the power disconnect switch without advance notice to Attachment Customer.

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e. Attachment Customer is solely responsible for ensuring compliance with all Federal Communication Commission antenna registration requirements, Federal Aviation Administration air hazard requirements, or similar requirements with respect to the location of Attachment Customer's Wireless Facilities on Company's poles.

f. Attachment Customer shall not operate its Wireless Facility in a way that causes interference with Company-owned wireless facilities. Attachment Customer shall, after receiving notice from Company of such interference, immediately cease operating its Wireless Facility until it can be operated without causing such interference

g. All power supplies, equipment cabinets, meter bases and other equipment associated with the Wireless Facilities that are large enough to impede accessibility shall be installed off-pole, consistent with the applicable standards of the NESC, Company standards, and all applicable laws, rules, regulations, ordinances, and other applicable governmental directives.

h. Attachment Customer shall not perform any construction, including but not limited to the initial installation of its Wireless Facilities or any maintenance thereof, above the Communications Space without receiving prior approval from Company as to the design, installation, and construction practices, which approval Company shall not unreasonably withhold.

10. OVERLASHING OF CABLE

An Attachment Customer may make an initial overlash of an existing attachment if the overlash is not greater than one-half inch in diameter without any advance notice or application to the Company. No application or advance notice is required for the replacement of an existing cable with a cable that is no greater than one-half inch in diameter. With all other overlashing, Attachment Customer shall provide Company with advance notice to permit Company to visually inspect its Structures to determine the need for a pole loading analysis. For projects involving more than ten (10) spans, the Attachment Customer must provide at least fifteen (15) business days' advance notice. For projects involving ten (10) spans or less, Attachment Customer shall provide at least seven (7) business days' advance notice. Notwithstanding the foregoing, no bundle of Attachment Customer's Cable shall exceed two inches in diameter without Company's express written approval.

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11. STRAND-MOUNTED WIRELESS COMMUNICATION DEVICES

A strand-mounted wireless communication device shall be considered part of wireline attachment and not subject to permitting or an additional attachment charge if it is located within the one (1) foot vertical space occupied by Attachment Customer's cable and meets all applicable loading, clearance, and RF emission requirements. Before deploying any strand-mounted wireless communications devices other than strand-mounted wi-fi access points, Attachment Customer shall at least sixty (60) days prior to planned deployment notify Company of the proposed deployment and provide sufficient information regarding the nature of device to permit Company to assess the safety and loadbearing implications of the proposed deployment.

12. MAINTENANCE OF ATTACHMENTS AND STRUCTURES

Attachment Customer shall maintain Attachments in safe condition and in good repair, in a manner reasonably suitable to Company and so as not to conflict with any use of Company facilities (including Structures) by Company or any other Person using such facilities pursuant to any license or permit by Company. Attachment Customer shall not interfere with the working use of any other Person's property on or in such facilities or any such property, which may be placed on or near the Structures and other facilities. Company reserves to itself, its successors, Affiliates and assigns, the right to maintain Structures and other Company property and to operate its business and maintain its property in such a manner as will, in its own judgment, best enable it to fulfill its own service requirements. Company shall not be liable to Attachment Customer for any interference with the operation of Attachment Customer's facilities, or loss of business arising in any manner out of the use of Company's Structures or other property.

13. NATIONAL JOINT UTILITIES NOTIFICATION SYSTEM

Within thirty (30) days of executing a Contract, and prior to making application for any Attachment, Attachment Customer will join National Joint Utilities Notification System ("NJUNS"), a web-based system developed to improve joint use communication, and will actively participate during the term of service, by entering field information into the NJUNS system within the times required by the system. Should Attachment Customer fail to actively participate in NJUNS and should such failure cause Company to incur expense or liability to others, Attachment Customer shall reimburse Company its expense and indemnify and hold Company harmless from any damages or liability arising out of such failure. If Company at a later date elects to use a different system for purposes of the communication currently facilitated by NJUNS, Company, shall notify Attachment Customer at least sixty (60) days in advance of such change and Attachment Customer shall make arrangements to participate in that system.

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14. INSPECTIONS/AUDITS

Company may make periodic inspections for the purpose of determining compliance with this Schedule and with the Contract. Neither Company's right to make inspections nor any inspection made by Company shall relieve an Attachment Customer of any responsibility, obligation or liability assumed under this Schedule.

Upon thirty (30) days' prior notice to Attachment Customer, Company may conduct an audit of its Structures to verify the number, location and type of Attachment Customer's Attachments. Company shall make available to Attachment Customer the report of such audit. Such report shall indicate the location and pole number of all attachments of the Attachment Customer. If the audit reveals that the number of Attachments exceeds the number of Attachments shown in Company's existing records, the excess number of Attachments shall be presumed to be Unauthorized Attachments. Attachment Customer shall have the right to rebut this presumption and demonstrate that the Attachments at issue were authorized. Attachment Customer shall reimburse Company for the expense of such audit, or its pro rata share of such expense if the Attachments of other Attachment Customers are included within the scope of the audit, within thirty (30) days of an invoice for such expenses.

15. INTERFERENCE OR HAZARD

If Company notifies Attachment Customer in writing or orally with written confirmation that the Attachment Customer's Attachments or the condition of Attachment Customer's Attachments on or in any Structure (i) interfere with the use of such Structure or the operation of Company facilities or equipment, (ii) constitute a hazard to the service rendered by Company or any other Persons permitted by Company to use such Structures, (iii) cause a danger to employees of Company or other Persons, or (iv) fail to comply with Company's standards and applicable requirements of the NESC, NEC, and all other applicable codes, laws and regulations, Attachment Customer shall, within a reasonable period, remove, rearrange, repair or change its Attachments as needed or as directed by Company. In the case of any immediate hazard or danger, such period shall not exceed twenty-four (24) hours from Attachment Customer's receipt of such notice. In case of a hazardous condition or other emergency which requires the immediate removal or relocation of the Attachment Customer's Attachments, Company may at Attachment Customer's expense, without prior notice and with no liability therefor, remove or relocate such Attachments; provided however, that Company shall notify Attachment Customer of such action as soon as reasonably possible by any appropriate means, including by telephone.

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16. REARRANGEMENT; RELOCATION OF STRUCTURES; NEW STRUCTURES

a. If Attachment Customer's Attachments can be accommodated on or in existing Structures only by rearranging Company facilities, or if because of Attachment Customer's proposed Attachments, Company rearranges or transfers its facilities on or in any facility not owned by it, Attachment Customer shall reimburse Company for the actual expense incurred in making such rearrangement or transfer.

b. Upon forty-five (45) days prior written notice delivered to Attachment Customer, Company may replace, relocate, or remove any Structure and cause the alteration, relocation or removal of any Attachment, consistent with normal operating, maintenance and development procedures and prudent utility practices. In cases of emergency or dangerous situations, Company shall give only as much prior notice as practical under the circumstances. Likewise, in situations where the Company is required to replace, relocate or remove any Structure in less than 45 days by state or local law, easement provisions, contractual obligations to third parties or to meet the Company's obligation to provide electric service to another customer, Company need provide only as much prior notice as reasonably practical under the circumstances, Company shall bear all costs and expenses of any relocation of the Structures not attributable to or caused by Attachment Customer or its Attachments. Attachment Customer shall bear all costs and expenses of any relocation and removal of the Attachments and all costs and expenses attributable to or caused by Attachment Customer or its Attachments. Attachment Customer shall be solely responsible for any losses occasioned by the interruption of Attachment Customer's business or operations and shall indemnify and hold Company harmless in connection with same.

c. Company may reserve space on its poles in accordance with a bona fide development plan for electric service. Company may direct, by written notice to Attachment Customer, that Attachment Customer's attachments in such reserve space may be removed from the Structures. Company shall use reasonable efforts to make space available as close in proximity as possible to the former Structures or to offer Attachment Customer the option to perform make-ready work to create additional space on the Structure in question. Attachment Customer shall make such relocation within sixty (60) days of Company's request.

d. In the event a Person other than Attachment Customer applies to make an Attachment to a Structure on which Attachment Customer has placed an Attachment, and such application requires that Attachment Customer rearrange, transfer or relocate its Attachments, then Attachment Customer shall perform such rearrangement, transfer or relocation within sixty (60) days of notice of such need to rearrange, transfer or relocate. Attachment Customer may condition its rearrangement, transfer or relocation upon reimbursement for the cost of such rearrangement, transfer or relocation. In the event Attachment Customer fails to perform such rearrangement, transfer or relocation within the time frame described above, the affected Attachments may be subject to rearrangement, transfer or relocation by the Person whose application necessitated the rearrangement, transfer or relocation to the extent permitted by law.

17. REMOVAL OF ATTACHMENT

Attachment Customer may at any time voluntarily remove its Attachments from any Structure, but shall immediately give Company written notice of such removal on Company-prescribed form. Attachment Customer shall bear all cost of removal and any costs that Company incurs as a result of such removal and shall pay such costs within thirty (30) days of receipt of an invoice. No refund of any amount paid for use of such Structure will result from Attachment Customer's voluntary removal nor shall such voluntary removal affect any other obligation or liability of Attachment Customer under this Schedule or the Contract.

18. INDEMNITIES

Attachment Customer shall protect, defend, indemnify and save harmless Company, its Affiliates, their officers, directors, employees and representatives from and against 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, payment of any settlement or judgment therefor and reasonable attorney's fees that are incurred in such defense, by reason of any claims arising from Attachment Customer's activities under this Schedule, or the Contract, or from Attachment Customer's presence on Company's premises, or from or in connection with the construction, installation, operation, maintenance, presence, replacement, enlargement, use or removal of any facility of Attachment Customer attached or in the process or being attached to or removed from any Company Structure by Attachment Customer, its employees, agents, or other representatives, including but not limited to claims alleging (1) injuries or deaths to Persons; (2) damage to or destruction of property including loss of use thereof; (3) power or communications outage, interruption or degradation; (4) pollution, contamination of or other adverse effects on the environment; (5) violation of governmental laws, regulations or orders; or (6) rearrangement, transfer, or removal of any third party attachment on, from, or to any Company Structure whether suffered directly by Company itself or indirectly by reason of claims, demands or suits against it by third parties, resulting or alleged to have resulted from Attachment Customer's activities under this Schedule, or the Contract, or from Attachment Customer's presence on

Company's premises, or from or in connection with the construction, installation, operation, maintenance, presence, replacement, enlargement, use or removal of any facility of Attachment Customer attached or in the process or being attached to or removed from any Company Structure by Attachment Customer, its employees, agents, or other representatives. The indemnity set forth in this section shall include indemnity for any claims arising out of the joint negligence of Attachment Customer and Company; provided however, the indemnity set forth in this section, but not Attachment Customer's duty to defend, shall be reduced to the extent it is established by final adjudication or mutual agreement of Attachment Customer and Company that the liability to which such indemnity applies was caused by the negligence or willful misconduct of Company. If Attachment Customer is required under this provision to indemnify Company, Attachment Customer shall have the right to select defense counsel and to direct the defense or settlement of any such claim or suit.

19. UNAUTHORIZED ATTACHMENTS

If Attachment Customer makes any Attachment that requires Company approval or advance notice under this Schedule or the Contract and has not obtained such approval or provided such advance notice, such Attachment shall be deemed an "Unauthorized Attachment," and shall be presumed to have been affixed to Company Structures for two years or since completion of the most recent audit, whichever is occurring earlier. Attachment Customer shall be liable for attachment charges for this time period. In addition to the attachment charges for the period of unauthorized attachment, Attachment Customer shall pay a penalty for each Unauthorized Attachment in the amount of $25.00. Attachment Customer shall also submit to Company an application for approval of the Unauthorized Attachment within thirty (30) days of the attachment's discovery. If Attachment Customer fails to submit the required applications or fails to timely remit any necessary payments to Company in connection with the application process (including but not limited to any make-ready fees necessary to accommodate the Unauthorized Attachments), Company may remove any or all such Unauthorized Attachments at Attachment Customer's expense.

20. DEFAULT

a. If Attachment Customer fails to pay any undisputed fee required, perform any material obligations undertaken or satisfy any warranty or representation made under the Contract comply with any of the provisions of this rate schedule or default in any of its obligations under this Schedule, including Section 5 of the Company's Electric Tariff, and shall fail within thirty (30) days after written notice from Company to correct such default or non-compliance, Company may, at its option, terminate the license covering the Structures to which such default or non-compliance is applicable; remove, relocate or rearrange at Attachment Customer's expense the Attachments to which the default or non-compliance relates; or decline to permit additional Attachments until the failure or default is cured. Company shall give written notice to Attachment Customer of said termination. In the event of material or repeated default, Company may terminate the Contract and recover from Attachment Customer all costs and expenses incurred as a result of related to the defaults. No refund of any attachment charge will be due on account of such termination.

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21. TERMINATION

Attachment Customer may terminate a Contract by providing Company written notice of termination at least sixty (60) days prior to the end of the term of service.

Upon termination, Attachment Customer shall remove all Attachments from Structures and other Company property within 180 days. Attachment Customer shall bear all costs of such removal and shall exercise precautions to avoid damage to all Persons and to facilities of Company and other parties in so removing Attachments and assumes all responsibility for all damage it causes. If Attachment Customer's Attachments and other property are not removed within 180 days of termination of this Agreement, unless the time is extended by mutual agreement, Company may remove Attachment Customer's Attachments without liability and Attachment Customer shall pay Company the cost of such removal within thirty (30) days of receipt of an invoice.

Company may terminate a Contract without liability to Attachment Customer, upon giving sixty (60) days advance written notice to Attachment Customer that it has a reasonable belief that Company's performance under the Contract would be illegal under applicable law or regulation or under any order or ruling issued by the PSC, or any other federal, state or local agency having regulatory jurisdiction over Company and same cannot be cured by Company without unreasonable expense or without materially and substantially altering the terms and conditions of the Contract; or that termination is required to preserve Company's rights under any franchise, right-of-way, permit, easement or other similar right which is material and substantial to Company's business or operations. In the event of such termination, Company and Attachment Customer shall pay and perform obligations that have arisen prior to the effective date of termination, but shall not be obligated to pay and perform obligations, which arise after the effective date of termination.

22. WAIVER

Failure by Company to enforce or insist upon compliance with any of the terms or conditions of this Schedule or the Contract shall not constitute a general waiver or relinquishment of any such terms or conditions, but the same shall be and remain at all times in full force and effect.

23. INSURANCE

a. Throughout the term of service and so long as Attachment Customer's Attachments are on or in Company Structures, Attachment Customer shall, at its own expense, maintain and carry in full force and effect insurance that meets at least the following requirements (these minimum limits should not be deemed to replace Attachment Customer's full obligation under this Schedule or the Contract):

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(1) Workers' Compensation and Employer's Liability Policy, which shall include: (a) Workers' Compensation (Coverage A); (b) Employer's Liability (Coverage B) with minimum limits of $1,000,000 Bodily Injury by Accident, each Accident, $1,000,000 Bodily Injury by Disease, each Employee; (c) Thirty (30) Day Cancellation Endorsement; and (d) All States Endorsement.

(2) Commercial General Liability Policy, which shall have minimum limits of $1,000,000 each occurrence; $1,000,000 Products/Completed Operations Aggregate each occurrence; $1,000,000 Personal and Advertising Injury each occurrence, in all cases subject to $2,000,000 in the General Aggregate for all such claims, and including: (a) Thirty (30) Day Cancellation Endorsement; (b) Blanket Written Contractual Liability to the extent covered by the policy against liability assumed by Company under the Attachment Customer Agreement; (c) Broad Form Property Damage; (d) General Aggregate Limit – Per Project Endorsement (CG2503); (e) Include Additional Insured Endorsement GC 2010 or CG2037, or its equivalent; and (f) Insurance for liability arising out of blasting, collapse, and underground damage (deletion of X, C, U Exclusions).

(3) Commercial Automobile Liability Insurance covering the use of all owned, non-owned, and hired automobiles, with a bodily injury, including death, and property damage combined single minimum limit of $1,000,000 each occurrence.

(4) Umbrella/Excess Liability Insurance with minimum limits of $5,000,000 per occurrence; $5,000,000 aggregate, to apply to employer's liability, commercial general liability, and commercial automobile liability; including: (a) "Follow Form" provisions; and (b) Note that Total Limits can be met by any combination of primary and umbrella/excess policies.

(5) Aircraft Public Liability - Required at all times when there will be use of any type of fixed wing, rotor, or any type aircraft to perform any work required under this Schedule or the Contract. Aircraft Public Liability Insurance covering such aircraft whether owned, non-owned, leased, hired or assigned with a combined single minimum limit for bodily injury and property damage of $5,000,000 including passenger liability coverage.

(6) Drones – Required at all times if any Unmanned Aircraft Systems (UAS) will be used by Contractor or Subcontractor in performing the work required under this Schedule or the Contract, Drone Liability Insurance covering such aircraft whether owned, non-owned, leased, hired or assigned with a
$1,000,000 per occurrence combined single limit for bodily injury, property damage and personal injury.

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(7) Professional Liability - To the extent the work required under this Schedule or the Contract includes any professional services that falls within a professional liability exclusion from the policy provided under Section 23a.(2). Coverage required with limits of Five Million Dollars ($5,000,000) per claim and Five Million Dollars ($5,000,000) in the aggregate, which insurance shall be on a claims made basis. Policy to remain in force continuously for three (3) years or an extended discovery period will be exercised for a period of three (3) years beginning from the time the services under this contract are completed.

b. Attachment Customer shall require its Contractors and subcontractors to provide and maintain the same insurance coverage as required of Attachment Customer.

c. Except with regard to workers' compensation and professional liability, each policy required under this Schedule shall name Company and all its Affiliates as an additional insured and shall waive rights of subrogation against Company, all its Affiliates, and Company's insurance carrier(s). All policies shall be primary and non-contributory. Condition applies to Attachment Customer and its Contractors and Subcontractors.

d. All policies shall be written by insurance companies that are either satisfactory to Company or have an A.M. Best Rating of not less than "A-, VII". These policies shall not be materially changed or canceled except with thirty (30) days written notice to Company from Attachment Customer and the insurance carrier. Attention: Manager, Project Manager – Third Party Attachments, LG&E and KU Services Company, P.O. Box 32020, Louisville, Kentucky 40232.

e. Company may request a summary of coverage of any of the required policies or endorsements; but is not obligated to review any of Attachment Customer's certificates of insurance, insurance policies, or endorsements, or to advise Attachment Customer of any deficiencies in such documents. Company's receipt or review of such documents shall not relieve Attachment Customer from or be deemed a waiver of Attachment Customer's obligations to maintain insurance as provided. Attachment Customer shall provide a summary of coverage within (thirty) 30 days of its request by the Company.

f. Attachment Customer shall provide Certificates of Insurance to Company for each policy of insurance required above and evidence the items noted hereafter: (1) Each Certificate shall properly identify the certificate holder as Company; (2) Under no circumstances shall Attachment Customer begin any work (or allow any Subcontractor to begin any work) prior to submitting Certificate(s) (evidencing the required insurance of Contractor or Subcontractor, as applicable) acceptable to Company. Company retains the right to waive this requirement at its sole discretion; (3) Certificate shall evidence (thirty) 30 days prior notice of cancellation; (4) Certificate shall verify additional insured status on all

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coverage including the endorsements required by Section 23a.(2); (5) Certificate shall verify Blanket Waiver of subrogation - All policies of insurance shall include waivers of subrogation, under subrogation or otherwise, against Company. Except where not applicable by law; (6) Certificate shall verify Primary/Non-contributory wording in favor of Company; and (7) Certificate shall identify policies which are written on a Claims Made coverage form and state the retro date.

g. Attachment Customer shall notify Company, prior to the commencement of any work pursuant to this rate Schedule or the Contract , of any threatened, pending and/or paid off claims to third parties, individually or in the aggregate, which otherwise affects the availability of the limits of such coverage(s) inuring to Company's benefit.

h. Attachment Customer shall provide notice of any accidents, occurences, or claims involving Attachment Customer's Attachment or Attachment Customer's work under this Schedule and the Contract to the LKS Manager, Risk Management at LG&E and KU Services Company, P.O. Box 32030, Louisville, Kentucky 40232.

i. Each policy of insurance required to be maintained by Attachment Customer under this Section 23 (except the Workers' Compensation and Employer's Liability Policy) shall cover all losses and claims of Attachment Customer regardless of whether they arise directly to Attachment Customer or indirectly through Subcontractors (e.g., Attachment Customer's CGL policy must cover Attachment Customer and additional insureds against negligent acts of a Subcontractor, etc.). Section 23 only represents minimum insurance requirements; it does not mitigate or reduce liability required by the indemnity provisions in this Schedule or the Contract. Nor should it be deemed to be the full responsibility of the contractor or subcontractor for liability. Attachment Customer is responsible for their subcontractor's insurance meeting the requirements of Section 23 of this Schedule.

j. Attachment Customer may elect not to comply with sections (a) through (i) of this Section 23 if it provides proof of equivalent levels of self-insurance and:

   1. Attachment Customer has been in business at least three (3) years and has a corporate credit rating or a senior unsecured rating of at least Baa2 (Moody's) or BBB (Standard & Poor's); or

   2. Attachment Customer has been in business at least three (3) years, and provides its most recent audited financial statements to Company which demonstrates that Attachment Customer meets standards that are at least equivalent to the standards underlying the credit ratings of Baa2 (Moody's) or BBB (Standard and Poor's); or,

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3. A corporate entity affiliated with Attachment Customer ("Guarantor") meets the criteria set out in (1) or (2) above, and Guarantor provides a written guarantee (in a form acceptable to Company, that the corporate affiliate will guarantee all financial obligations associated with Attachment Customer's use of Company's Structures.)

24. PERFORMANCE ASSURANCE

a. Attachment Customer shall furnish Performance Assurance in the following amounts to guarantee the payment of any sums which may become due for attachment charges, inspections, or work performed by the Company under this Schedule or the Contract, including the removal of attachments upon termination of the Contract by any of its provisions:

Number of Attachments	Amount per Attachment	Maximum Total
1-5,000	$20/Attachment	$100,000
5,001-10,000	$10/Attachment	$150,000
10,001+	$5/Attachment	$1,000,000

The above-stated amounts are incremental. By way of example, 7,500 Attachments would require Performance Assurance in the amount of $125,000 ($20 per Attachment for the first 5000 Attachments; $10 per Attachment for the next 2,500 Attachments); 15,000 Attachments would require Performance Assurance in the amount of $175,000 ($20 per Attachment for the first 5000 Attachments; $10 per Attachment the next 5,000 Attachments; and $5 per Attachment for the last 5,000 Attachments).

The amount of the Performance Assurance shall be calculated by the Company annually based on the Attachment Customer's then-existing number of Attachments. Attachment Customer shall provide the Performance Assurance within 30 days of its request by the Company.

If Attachment Customer proposes to attach a Wireless Facility or Facilities to a Structure, Attachment Customer shall post Performance Assurance in the amount of $1,500 for each pole to which a wireless attachment is attached. The amount of the Performance Assurance shall not be reduced upon completion of installation or other event.

In the event the Customer provides Performance Assurance in the form of a surety bond or Letter of Credit, each bond or Letter of Credit shall contain the provision that it shall not be terminated prior to six (6) months after Company's receipt of written notice of the desire of the bonding or insurance company, or bank, to terminate such bond or Letter of Credit. Company may waive this requirement if an acceptable replacement is received before the six (6) months has ended. Upon termination of such surety bond or Letter of

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Credit, , Company shall request Attachment Customer to immediately remove its Cables, Wireless Facilities, Attachments and all other facilities from Company Structures. If Attachment Customer should fail to complete the removal of all of its facilities from Company's Structures within (thirty) 30 days after receipt of such request, then Company may remove Attachment Customer's facilities at Attachment Customer's expense and without liability for any damage to Attachment Customer's facilities.

Each surety bond shall be issued by an entity having a minimum A.M. Best rating of A- and/or Letter of Credit shall be issued by an entity having a minimum Credit Rating of A- by S& P or A3 by Moody's at the time of issuance and at all times the relevant instrument is outstanding.

b. Attachment Customer may elect not to provide Performance Assurance if:

1. Attachment Customer has been in business at least one (1) year and has a corporate credit rating or a senior unsecured rating of at least Baa2 (Moody's) or BBB (S&P's); or

2. Attachment Customer has been in business at least one (1) year, and provides its most recent audited financial statements to Company which demonstrates that Attachment Customer meets standards that are at least equivalent to the standards underlying the credit ratings of Baa2 (Moody's) or BBB (S&P's); or,

3. A corporate affiliate of Attachment Customer ("Guarantor") meets the criteria set out in (1) or (2) above, and Guarantor provides a written guarantee (in a form acceptable to Company, that the corporate affiliate will guarantee all financial obligations associated with Attachment Customer's use of Company's Structures).

Annually, upon the Company's request, an Attachment Customer electing not to provide Performance Assurance under one of the options in c. above shall provide Company with such information as Company requires to determine whether Attachment Customer remains eligible to make such election.

25. CERTIFICATION OF NOTICE REQUIREMENTS

Attachment Customer's highest ranking officer located in Kentucky shall certify under oath on or before January 31 of each year that the Attachment Customer has complied with all notification requirements of this Schedule. The certification shall be in the form prescribed by Company from time to time, and Company shall provide the current version of such form on or after January 1 of each year. If Attachment Customer does not have an officer located in Kentucky, then the certification shall be provided by the officer with responsibility for Attachment Customer's operations in Kentucky.

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26. NOTICES

Any notice, or request, required by this Schedule or the Attachment Customer Agreement shall be deemed properly given if sent overnight by nationally recognized overnight courier, sent by certified U.S. mail, return receipt requested, postage prepaid, or sent by telecopier with confirmed receipt, to Company's and Attachment Customer's designated representative. The designation of the representative to be notified, his address and/or telecopier number may be changed at any time by similar notice.

27. LIENS

To the extent permitted by law, in the event any construction lien or other encumbrance shall be placed on the Attachments as a result of the actions or omissions of Attachment Customer or its Contractor, Attachment Customer shall promptly, in accordance with applicable laws, discharge such lien or encumbrance without cost or expense to Company. Attachment Customer shall indemnify Company for any and all actual damages that may be suffered or incurred by Company in discharging or releasing said lien or encumbrance.

28. FORCE MAJEURE

In the event Attachment Customer or Company is delayed in or prevented from performing any of its respective obligations under an Attachment Customer Agreement or this Schedule due to acts of God, war, riots, civil insurrection, acts of the public enemy, strikes, lockouts, acts of civil or military authority, government shutdown, fires, floods, earthquakes, storms and other major disruptive events, fiber, cable or other material failures, shortages or unavailability, delay in delivery not resulting from its failure to timely place orders therefor, lack or delay in transportation, or due to any other causes beyond its reasonable control, then such delay or nonperformance shall be excused.

29. LIMITATION OF LIABILITY

IN NO EVENT SHALL COMPANY OR ANY OF ITS REPRESENTATIVES BE LIABLE UNDER A CONTRACT OR THIS SCHEDULE TO ATTACHMENT CUSTOMER FOR CONSEQUENTIAL, INDIRECT, INCIDENTAL, SPECIAL, EXEMPLARY, PUNITIVE OR ENHANCED DAMAGES, LOST PROFITS OR REVENUES OR DIMINUTION IN VALUE, ARISING OUT OF, OR RELATING TO, OR IN CONNECTION WITH ACONTRACT OR THIS SCHEDULE, REGARDLESS OF (A) WHETHER SUCH DAMAGES WERE FORESEEABLE, (B) WHETHER OR NOT COMPANY WAS ADVISED OF THE POSSIBILITY OF SUCH DAMAGES AND (C) THE LEGAL OR EQUITABLE THEORY (CONTRACT, TORT OR OTHERWISE) UPON WHICH THE CLAIM IS BASED. THE LIMITATIONS SET FORTH IN THIS SECTION 29 SHALL NOT APPLY TO DAMAGES OR LIABILITY ARISING FROM THE GROSSLY NEGLIGENT ACTS OR OMISSIONS OR WILLFUL MISCONDUCT OF COMPANY IN PERFORMING ITS OBLIGATIONS UNDER AN ATTACHMENT CUSTOMER AGREEMENT OR THIS SCHEDULE.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Electric Vehicle Supply Equipment

APPLICABLE

In all territory served.

AVAILABILITY T

Available to Customers to be served or currently being served under Rates GS (with energy usage of 500 kWh or higher per month), AES, PS, TODS, TODP, RTS, and FLS, for the purpose of charging electric vehicles. T T

Charging station is offered under the conditions set out hereinafter for electric vehicle supply equipment such as, but not limited to, the charging of electric vehicles via street parking, parking lots, and other outdoor areas.

A basic underground service includes the charging station, existing transformer (or secondary pedestal) and 208/240 volt single-phase service, and necessary conductor and equipment typical of an underground service drop. Said service drop can originate from underground or overhead equipment. Company will furnish, own, install, and maintain the charging unit and cable. Customer will furnish, own and install all duct systems and associated equipment.

Where the location of existing facilities is not suitable, 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.

Company will coordinate charging station installation with Company's current charging station supplier and Customer. Customer shall be responsible for the charging equipment installation costs. T T

Service will be provided under written contract, signed by Customer prior to service commencing.

RATE	Single Charger	Dual Charger	
Monthly Charging Unit Fee:	$134.34	$196.64	R/R

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D
School Tax	Sheet No. 91	

ENERGY CONSUMPTION

Determination of energy applies to the non-metered charging station. The applicable fuel clause charge or credit will be based on an annual 5,852 kilowatt-hours.

PAYMENT

The EVSE charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

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. Cancellation by Customer prior to the expiration of the initial term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the initial term of the contract.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions in this Tariff Book, except as set out herein. T

2. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for installation.

3. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and Customer. Where attachment of Customer's devices and/or equipment is made to Company facilities, Customer must have an attachment agreement with Company. T

4. 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.

TERMS AND CONDITIONS (continued)

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

6. If Customer requests the removal of an existing charging station, including, but not limited to, poles, or other supporting facilities that were in service less than twenty (20) years, and requests installation of replacement facilities within five (5) years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.

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

8. 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.

9. Notwithstanding the provisions of 807 KAR 5:006, Section 14(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 service shall furnish Company with realistic estimates of prospective electricity requirements.

10. Customer shall agree to permit Company to obtain specific charging station usage data directly from the Charging Station Supplier.

MINIMUM CHARGE

The Monthly Charging Unit Fee shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00370 dated June 22, 2017 and modified June 29, 2017

Standard Rate **EVC**

Electric Vehicle Charging

APPLICABLE

In all territory served.

AVAILABILITY T

Available to operators of licensed electric vehicles (EV). EV Customer is defined as the party who owns/operates a licensed electric vehicle, connects that vehicle for the purpose of receiving vehicle charging service to a Company-owned charging station providing service under this schedule, and willingly accepts Company's fee structure for the vehicle charging service. EV is T offered under the conditions set out hereinafter for the purpose of charging EVs via street parking, parking lots, and other outdoor areas. EV Customers' charging systems must meet applicable charging standards. Service under this rate schedule is limited to a maximum of ten stations. N Company will accept Customers on a first-come-first-served basis N

Company assumes no liability or responsibility for any potential automotive-related incidents that occur at specific charging locations. EV Customer accepts all restrictions related to the temporary parking space.

RATE

Fee for First Two (2) Hours:	$0.75 per Hour	T/R
Fee for Every Hour After First Two (2) Hours:	$1.00 per Hour	N/R

Charging Unit Fee includes an Energy Charge, adjustment clauses, and applicable T
franchise fee and tax. T

Charging sessions of less than a full hour will be prorated.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above includes the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87

The bill amount specified above will be increased or decreased in accordance with the following: D

Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

TERMS AND CONDITIONS

1. Service shall be furnished under the following Terms and Conditions and excludes Company's Terms and Conditions set out in this Tariff Book. T

2. EV Customer is required to pay by means of credit card or Charging Station Supplier account.
   a. Credit Card must be chip enabled (if card is not chip enabled, Customer must call the Charging Station Supplier at toll-free number provided at station), or
   b. EV Customer is required to open a Charging Station Supplier account and accepts all terms and conditions of Charging Station Supplier.

3. 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.

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

5. In no event shall Company have any liability to EV Customer, the owner of a vehicle receiving charging service, or any other party affected by the electrical service to EV 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 EV Customer, the owner of a vehicle receiving charging service, or any other party. In the event that EV Customer's use of Company's service causes damage to Company's property or injuries to persons, EV 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.

6. By connecting a vehicle to the Charging Station, the EV Customer represents that the EV Customer is authorized to operate that vehicle and to connect it to the Charging Station for the purpose of receiving vehicle charging service.

7. All service and maintenance will be performed only during regular scheduled working hours of Company.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00294 dated ____

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 $3.00 to cover the additional processing costs. R

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 19, and the results show the meter is within the limits allowed by 807 KAR 5:041, Section 17(1), the Customer will be charged $75.00 to cover the test and transportation costs.

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 occurs. No charge will be made for Customers qualifying T
for service reconnection pursuant to 807 KAR 5:006, Section 16, 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 $28.00 to cover disconnection and reconnection of electric service, such charge to be made before reconnection occurs. T

METER PULSE CHARGE

Where a Customer desires and Company is willing to provide data meter pulses, a charge of $25.00 I
per month per installed set of pulse-generating equipment will be made to those data pulses. Time pulses will not be supplied.

Special Charges

UNAUTHORIZED RECONNECT CHARGE

When Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service: T

1. A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;

2. A charge of $90.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter;

3. A charge of $110.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter;

4. A charge of $174.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Advanced Metering System (AMS) meter; or T

5. A charge of $177.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

APPLICABLE

In all territory served.

AVAILABILITY T

Availability limited to Customers served under applicable rate schedules who contract for not less than 1,000 kVA individually, and executed a contract under this rider prior to July 1, 2017. Company will not enter into contracts for additional curtailable demand, even with Customers already participating in this rider, on or after July 1, 2017. 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 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. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than sixty (60) minutes notice when either requesting or canceling a curtailment. T

Company may request at its sole discretion up to 100 hours of physical curtailment per year. Company will request physical curtailment only when (1) all available units have been dispatched or are being dispatched and (2) all off-system sales have been or are being curtailed. 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. Customers choosing to curtail rather than buy through during any of the 275 hours of Company-requested curtailment with a buy-through option each year shall not reduce, diminish, or detract from the 100 hours of physical curtailment Company may request each year.

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 in kVA. 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 kVA demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance.

Option B -- Customer may contract for a given amount of curtailable load in kVA 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 in kVA 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 in kVA 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) Customer's maximum demand during such curtailment. T

RATE

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

Transmission Voltage Service:	$3.20 per kVA of Curtailable Billing Demand
Primary Voltage Service:	$3.31 per kVA of Curtailable Billing Demand

Non-Compliance Charge: $16.00 per kVA

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. Company and Customer may arrange to have installed, at T
Customer's expense, the necessary telecommunication and control equipment to allow Company T
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) Customer's measured maximum demand during the billing period for any billing interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M,(EST) and (ii) for the months October continuously through April, from 6 A.M. to 10 P.M, (EST) and (b) the firm contract demand. T

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

AUTOMATIC BUY-THROUGH PRICE

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

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

Where: NGP is the Cash Price for "Natural Gas, Henry Hub" as posted in *The Wall Street Journal* on-line for the most recent day for which a price is posted that precedes the day in which the buy-through occurred.

CERTIFICATION

Upon commencement of service hereunder, Customer shall be required to demonstrate or certify to Company's satisfaction the ability to comply with physical curtailment. On an annual basis, Customer will be required to certify continued capability to reduce its demand pursuant to the amount designated in the contract in the event of a request for curtailment. Failure to demonstrate or certify the capability to reduce demand pursuant to the amount designated in the contract may result in termination of service under this rider. T 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 Company requests curtailment, upon request by Customer, Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by Company, Customer shall provide to Company a good-faith, non-binding short-term operational schedule for their facility. T T

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

Standard Rate Rider **CSR-2**

Curtailable Service Rider-2

APPLICABLE

In all territory served.

AVAILABILITY T

Availability limited to Customers served under applicable rate schedules who contract for not less than 1,000 kVA individually, and executed a contract under this rider prior to July 1, 2017. Company will not enter into contracts for additional curtailable demand, even with Customers already participating in this rider, on or after July 1, 2017. 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 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. Company may request or cancel a curtailment at any time during any hour of the year. T

Company may request at its sole discretion physical curtailment no more than twenty (20) times per calendar year totaling no more than 100 hours. Company will request physical curtailment only when more than ten (10) of the Companies' primary combustion turbines (CTs) (those with a capacity greater than 100 MW) are being dispatched, irrespective of whether the Companies are making off-system sales. However, to avoid a physical curtailment a CSR Customer may buy through a requested curtailment at the Automatic Buy-Through Price. Any buy-through of a physical curtailment request will not count toward the 100-hour limit or 20-curtailment-request limit, but will count toward the 275 hours under the buy-through option discussed below. If all available units have been dispatched or are being dispatched, Company may request physical curtailment without a buy-through option. After receiving a physical curtailment request from Company where a buy-through option is available, a CSR Customer will have 10 minutes to inform Company whether the Customer elects to buy through or physically curtail. If the Customer elects to physically curtail, the Customer will have 30 minutes to carry out the required physical curtailment (i.e., a total of 40 minutes from the time Company requests curtailment to the time the Customer must implement the curtailment). If a Customer does not respond within 10 minutes of notice of a curtailment request from Company, the Customer will be assumed to have elected to buy through the requested curtailment, subject to any prior written agreement with the Customer. After receiving a physical curtailment request from Company when no buy-through option is available, a CSR Customer will have 40 minutes to carry out the required physical curtailment. T T T T T

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. Customers choosing to curtail rather than buy through during any of the 275 hours of Company-requested curtailment with a buy-through option each year shall not reduce, diminish, or detract from the 100 hours of physical curtailment Company may request each year. For such curtailments, Company will give no less than sixty (60) minutes notice when either requesting or canceling a curtailment.

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 in kVA. 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 kVA demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance.

Option B -- Customer may contract for a given amount of curtailable load in kVA 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 in kVA 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 in kVA 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) Customer's maximum demand during such curtailment. T

RATE

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

Transmission Voltage Service:	$ 5.90 per kVA of Curtailable Billing Demand
Primary Voltage Service:	$ 6.00 per kVA of Curtailable Billing Demand

Non-Compliance Charge: $16.00 per kVA

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. Company and Customer may arrange to have installed, at T
Customer's expense, the necessary telecommunication and control equipment to allow Company T
to control Customer's 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) Customer's measured maximum demand during the billing period for any billing interval during T
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.

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 is the Cash Price for "Natural Gas, Henry Hub" as posted in *The Wall Street Journal* on-line for the most recent day for which a price is posted that precedes the day in which the buy-through occurred.

CERTIFICATION

Upon commencement of service hereunder, Customer shall be required to demonstrate or certify to Company's satisfaction the ability to comply with physical curtailment. On an annual basis, Customer will be required to certify continued capability to reduce its demand pursuant to the amount designated in the contract in the event of a request for curtailment. Failure to demonstrate or certify the capability to reduce demand pursuant to the amount designated in the contract may result in termination of service under this rider. T T

TERM OF CONTRACT

The minimum original contract period shall be two (2) years 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 Company requests curtailment, upon request by Customer, Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by Company, Customer shall provide to Company a good-faith, non-binding short-term operational schedule for their facility. T T T

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 T

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 (on-peak hours)	$0.03229 per kWh
2. For winter billing months of December, January and February (on-peak hours)	$0.02852 per kWh
3. During all other hours (off-peak hours)	$0.02666 per kWh

On-peak hours for summer billing months of June through September are defined as weekdays (exclusive of holidays) from 8:01 A.M. to 9:00 P.M., Eastern Standard Time (under 1 above).

On-peak hours for winter billing months of December through February are defined as weekdays (exclusive of holidays) from 6:01 A.M. to 9:00 P.M., Eastern Standard Time (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	$0.02758 per kWh

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

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 sixteen (16) business days (no less than twenty-two (22) calendar 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.

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On and After December 5, 1985

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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

Kentucky Utilities Company

Standard Rate Rider **LQF**

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE T

In all territory served.

AVAILABILITY T

Available 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. T

RATES FOR PURCHASES FROM QUALIFYING FACILITIES

Energy Component Payments

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

Capacity Component Payments

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

Determination of CAP_i

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

1. System demand is less than or equal to Company's capacity:
   $D_1 \leq C_{KU}$; $CAP_i = 0$
2. System demand is greater than Company's capacity but less than or equal to the total of Company's capacity and the capacity provided by a QF:

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

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

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

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

PAYMENT

Company shall pay each bill for electric power rendered to it in accordance with the terms of the contract, within sixteen (16) business days (no less than twenty-two (22) calendar days) of the date the bill is rendered. In lieu of such payment plan, Company will, upon written request, credit Customer's account for such purchases. T

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.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Standard Rate Rider **NMS**

Net Metering Service

APPLICABLE

In all territory served.

AVAILABILITY T

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. Standard Rate Rider NMS is intended to comply with all provisions of the Interconnection and Net T Metering Guidelines approved by the Kentucky Public Service Commission, 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.

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. A billing period credit is a kWh-denominated electricity credit only, not a monetary credit.

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 Customer. This provision does not relieve Customer's responsibility to pay metering T costs embedded in Company's Commission-approved base rates. Additional meters, requested T 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 billing-period credit for the net delivery on Customer's bill for the succeeding billing periods. If Customer takes service under a time-of-use or time-of-day rate schedule, Company will apply billing-period credits Customer creates in a particular time-of-day or time-of-use block only to offset net energy consumption in the same time-of-day or time-of-use block; such credits will not be used to offset T net energy consumption in other time-of-day or time-of-use blocks in any billing period. Any such unused excess billing-period credits will be carried forward and drawn on by Customer as needed. Unused excess billing-period credits existing at the time Customer's service is terminated end with Customer's account and are not transferrable between Customers or locations.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

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 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.

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2014-00371 dated June 30, 2015

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

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, Company will notify Customer, and the time between notification and submission of T
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 Company's technical interconnection T
requirements. Those requirements are available on line at www.lge-ku.com and upon request.

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 T
to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, Company will notify Customer, and the time between notification and submission of T
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 Company T
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.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

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 Kentucky Public Service Commission;
   d. the rules and regulations of the Kentucky Public Service Commission, as may be revised by time-to-time by the Kentucky Public Service Commission:
   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 Company T
shall be responsible for repair of damage caused to the net metering generator resulting T
solely from the negligence or willful misconduct on the part of Company. T
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 rider. T

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CONDITIONS OF INTERCONNECTION (continued)

7. Where required by 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. T

   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 Customer to discontinue operation of the net metering generator if Company believes that: T
   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 rider, and the non-compliance adversely affects the safety, reliability or power quality of Company's electric system; or T
   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 Company is unable to immediately isolate or cause Customer to isolate only the net metering generator, Company may isolate Customer's entire facility. T
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

CONDITIONS OF INTERCONNECTION (continued)

of persons or damage to property caused by Customer or Customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating 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 Company has been made and verification that the installation is in compliance T
with this tariff. Upon written notification that an approved generating facility is being transferred to another person, Customer, or location, Company will verify that the installation T
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, Company will T
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.

TERMS AND CONDITIONS

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

LEVEL 1

Application for Interconnection and Net Metering

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

Submit this Application to:

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

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

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

Customer Name: ____________________ Account Number: ____________

Customer Address: ____________________

Customer Phone No.: ____________ Customer E-mail Address: ____________________

Project Contact Person: ____________________

Phone No.: ____________ E-mail Address (Optional): ____________________

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

____

Energy Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Inverter Manufacturer and Model #: ____________________

Inverter Power Rating: ____________ Inverter Voltage Rating: ____________

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

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

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

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

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

Expected Start-up Date: ____________________

LEVEL 2

Application for Interconnection and Net Metering

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

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

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

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

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

Customer Name: ______________________ Account Number: ______________

Customer Address: ______________________________________

Project Contact Person: ______________________________________

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

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

____

____

____

Total Generating Capacity of Generating Facility: ____

Type of Generator: ____Inverter-Based ____Synchronous ____Induction

Power Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

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

1. Single-line diagram of 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. T
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

APPLICABLE T
In all territory served.

AVAILABILITY T
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.

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.

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 1.20% 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:

Percentage With Contribution-in-Aid of-Construction 0.47% R

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

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Standard Rate Rider **RC**

Redundant Capacity

APPLICABLE

In all territory served. T

AVAILABILITY

Available to customers served under Company's rate schedules which include a demand charge or a special contract including a demand charge. T T

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

RATE:

Capacity Reservation Charge

Secondary Distribution	$1.16 per kW/kVA per month	I
Primary Distribution	$0.99 per kW/kVA per month	I

Applicable to the greater of:

1. the highest average load in kW/kVA (as is appropriate for the demand basis of the rate schedule 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. T

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Intermittent Loads

APPLICABLE

In all territory served.

AVAILABILITY T

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 Customer exceed T
the limits set forth in the IEEE standards for such characteristics. In addition, if Customer's use of T
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 Customer in accordance with T
807 KAR 5:006, Section 15(1)(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. 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 Customer's expense. T

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 Adjustment Clause and the Minimum Charge under such rate adjusted in accordance with (a) or T
(b) herein.

RATE (continued)

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-to-Permanent and Seasonal Service T

APPLICABLE

In all territory served.

AVAILABILITY T

This rider is available at the option of Company where:

1. Customer's business requires service provided for construction of permanent delivery points for residences and commercial buildings; or N N
2. Customer's business does not require permanent installation of Company's facilities and is of such nature to require only seasonal service or temporary service; or T
3. Customer's service is over 50 kW, provided for construction purposes, 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 T
4. Customer has need for temporary intermittent use of Company facilities and Company has facilities it is willing to provide Customer for installation and operational testing of Customer's equipment. T

This service is available for not less than one (1) month (approximately thirty (30) days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes. Where this service is provided under 3 or 4 above, Company will determine the term of service, which shall not exceed three (3) years. T T

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:

D

1. For Temporary-to-Permanent service which requires service for construction of permanent delivery points for residences and commercial buildings, the Company will provide a temporary electric service upon request by the customer for a non-refundable charge. This charge, which will be subject to an annual review and revision, shall depend on the facilities which must be installed (and removed) by the Company in order to connect service. N

   The standard charge shall be 15% of the estimated installation and removal cost where the facilities to provide service are already in place. It also applies where all of the installed facilities will be utilized, without modification, as part of a future permanent service.

CONDITIONS (continued)

2. For Seasonal Service where facilities are installed for temporary service that will not be utilized as part of a future permanent service, the 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.

Temporary services for underground or overhead installations are to be constructed as specified by Company standards. Customer will furnish and install material and equipment, including mast for service entrance, conductors, meter base, main disconnect, breaker assembly and grounding. Once the temporary service is no longer needed, the Customer must contact the Company for removal.

For such cases where a temporary service is written upon a refundable contract, the customer will be refunded back the deposit paid for the temporary service after three years of continuous service.

Standard Rate Rider

Kilowatt-Hours Consumed By Lighting Units

APPLICABLE

In all territory served to determine energy consumption applied to Company's non-metered lighting rate schedules. T

DETERMINATION OF ENERGY CONSUMPTION

The applicable Fuel Adjustment 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. T

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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 N

Green Tariff

APPLICABLE
In all territory served.

AVAILABILITY
Option #1: Renewable Energy Certificates (RECs)

Available as a rider to customers receiving service under Company's standard RS, RTOD, GS, 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.

Participation in this option may be limited by the ability of the Company to procure RECs from Renewable Resources at a price equal to $13 or less per REC. If the total of all kWh under contract under this tariff equals or exceeds the Company's ability to economically procure RECs (more than $13 per REC), the Company may suspend the availability of this tariff to new participants.

Option #2: Business Solar

Available as a rider to customers receiving service under Company's standard GS, PS, TODS, TODP, RTS, or FLS rate schedules. Service under Option #2 requires Company and Customer to enter into a special contract, which must be filed with and approved by the Kentucky Public Service Commission.

Participation in this option will be limited to Customers who wish to have the Company develop, procure, construct, maintain, manage, and own a solar array. The electrical energy produced by the array will be assigned to the Customer.

Option #3: Renewable Power Agreement

Available as a rider to customers to be served under Company's Standard Rate Schedules TODS, TODP, and RTS. Service under the Renewable Power requires Company and Customer to enter into a special contract, which must be filed with and approved by the Kentucky Public Service Commission.

Customers who wish to purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company. In addition this option is limited to:

1. A customer contracting for a minimum monthly billing load of 10 MVA (or MW as is appropriate).
2. Any agreement must be greater than 10 MW nameplate AC, capped at a system cumulative 50 MW name plate AC and for a term that equals the generation purchase agreement for a minimum period of 5 years.
3. Agreement must be for energy delivered to the Company's transmission system.
4. Energy serving this option must be generated from a renewable resource developed on or after the Kentucky Public Service Commission special contract approval date.

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Standard Rate Rider **GT** N

Green Tariff

DEFINITIONS

1. 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. The locations of these sources are limited to Kentucky, Indiana, Tennessee, Ohio, West Virginia, Virginia, Missouri, and Illinois that are certified for the creation of Renewable Energy Credits by definition 2 and 3 below.
2. 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 and attributes of one MWh of green power. RECs may only be purchased from facilities located in Kentucky, Indiana, Tennessee, Ohio, West Virginia, Virginia, Missouri, and Illinois.
3. Eligible RECs are created from renewable facilities verified and approved by the proven renewable asset tracking systems associated with the major regional Independent System Operators (ISO) operators, PJM's Generation Attribute Tracking System (GATS) or MISO's Midwest Renewable Energy Tracking System (MRETS). The legal ownership of every REC so created is recorded and tracked by GATS or MRETS to assure its authenticity and single ownership.

RATE

Option #1: RECs

Customers who wish to support the development of electricity generated by Renewable Resources may contract to purchase each month a specific number of incremental blocks. All RECs purchased to support Option #1 of this tariff shall be retired by the Company on behalf of the customers.

Rate Schedules RS and GS:
Voluntary monthly contributions of any amount in $5.00 increments

Rate Schedules PS, TODS, TODP, RTS, or FLS:
Voluntary monthly contributions of any amount in $13.00 increments

Option #2: Business Solar

Charges and energy credits for this service will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the firm service rates otherwise available to the Customer and the cost of the business solar facility being directly contracted for by the Customer.

N

Standard Rate Rider **GT**
Green Tariff

RATE - continued

Option #3: Renewable Power Agreement

Charges and energy credits for this service will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the firm service rates otherwise available to the Customer and the cost of the renewable energy resource, including appropriate transmission costs to deliver the energy to the Customer, being directly contracted for by the Customer.

TERM

Option #1: Customers may participate through a one-time purchase or an automatic monthly purchase agreement. Customer may terminate service under this rider by notifying the Company through its Call Center or Business Office. The charges will be removed on the Customer's next bill after their request to terminate.

Option #2: The term will be agreed upon in a separate written bilateral agreement between the Company and the Customer. Contract to be filed with and approved by the Kentucky Public Service Commission.

Option #3: The term will be agreed upon in the separate written bilateral agreement between the Company and the Customer. Contract to be filed with and approved by the Kentucky Public Service Commission.

TERMS AND CONDITIONS

1. Customers participating in Option #1 may contribute as much as they like in the dollar increments outlined above. (RS, GS - $5, $10, $15, $20, etc), (PS, TODS, TODP, RTS, FLS - $13, $26, $39, etc.)
2. An eligible Customer may participate in the Company's "Green Tariff" by making a request to Company's Call Center, Business Office, or through Company's website enrollment form. Funds provided by Customer to Company are not refundable.
3. Customers may not owe any arrearage prior to participating in the "Green Tariff". Any customer failing to pay the amount the customer pledged to contribute in Option #1 may be removed from the "Green Tariff". Any customer removed from or withdrawing Option #1 of the "Green Tariff" will not be allowed to re-apply for one year.
4. Customer will be billed monthly under the "Green Tariff". Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

Standard Rate Rider **EDR**

Economic Development Rider

APPLICABLE

In all territory served.

AVAILABILITY T

Available as a rider to Customers to be served or being served under Rates 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 Kentucky Public Service Commission. 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: D

For the twelve (12) consecutive monthly billings and the subsequent four consecutive twelve (12) monthly billing periods thereafter, the Total Demand Charge shall be reduced by 50%, 40%, 30%, 20%, 10% in the order of Customer's choosing at time of contract filing. All subsequent billing shall be at the full charges stated in the applicable rate schedule after this five (5) year period. N N N N

"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

1. 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).
2. EDR for Brownfield Development is available only to minimum monthly billing loads of 500 kVA or greater where the Customer takes service from existing Company facilities with no material changes. T T

Economic Development

3. Service under EDR for Economic Development is available to:
   a. new Customers contracting for a minimum monthly billing load of 1,000 kVA, and at least a 50% load factor; and T T

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TERMS AND CONDITIONS

Economic Development (continued)

b. Existing Customers contracting for a minimum monthly billing load of 1,000 kVA above their Existing Base Load, and at least a 50% load factor to be determined as follows: T
  i. Company and the existing Customer will determine Customer's Existing Base Load by calculating a twelve (12) month rolling average of measured demand. T
  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 Company and the Customer concerning the affected portion of the Customer's Existing Base Load.

4. A Customer desiring service under EDR for Economic Development must submit an application for service that includes:
   a. a description of the new load to be served;
   b. the number of new employees, if any, Customer anticipates employing associated with the new load;
   c. the capital investment Customer anticipates making associated with the EDR load;
   d. a certification that Customer has been qualified by the Commonwealth of Kentucky for benefits under the Kentucky Business Investment Program (KBI), or the Kentucky Industrial Revitalization Act (KIRA), or the Kentucky Jobs Retention Act (KJRA), or other comparable programs approved by the Commonwealth of Kentucky.

5. 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.

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N

Economic Re-Development

6. Service under EDR for Economic Re-Development is available to:
   a. Customers locating at vacant commercial or industrial properties in the Company's service territory which have been unoccupied for at least twelve (12) consecutive months. Verification of vacancy will constitute evidence of minimal to no electrical use during the unoccupied timeframe as determined by the company. Development of green space or undeveloped properties or sites are excluded from the Re-Development rider.
   b. EDR for Economic Re-Development is available only to minimum monthly billing loads of 500 kVA or greater where Customer takes service from the existing electrical infrastructure with no material changes and at least a 50% load factor.
   c. A customer desiring service under must submit an application for service that includes:
      i. a description of the new load to be served;
      ii. the number of new employees, if any, Customer anticipates employing associated with the new load; and
      iii. the capital investment Customer anticipates making associated with the EDR load.
   d. Customers relocating their operations from another premise within the Company's service territory and maintaining the same demand load as indicated on the customer's Load Data Sheet are ineligible to participate in this tariff.
   e. Customers relocating their operations from another premise within the Company's service territory and increasing the demand load as indicated on the customer's Load Data Sheet are eligible to participate in this tariff for the increased demand of 500 kVA minimum and at least a 50% load factor.
   f. 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, that amount shall be determined over a fifteen (15) year period and payable at the end of the fifteen (15) year period.

General

7. 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.
8. Customer may request an EDR effective initial billing date that is no later than twelve (12) months after the date on which the Kentucky Public Service Commission approves the customer agreement.
9. 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.

N

10. 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 Kentucky Public Service Commission.
11. No credit under EDR will be calculated or applied to Customer's billing in any billing month in which Customer's metered load is less than the load required to be eligible for either Brownfield Development, Economic Development, or Economic Re-Development.
12. EDR is not available to a new customer that results solely from a change in ownership of a previous customer's account. However, if a change in ownership occurs after the previous customer had entered into an EDR special contract, the successor customer may be allowed to fulfil the balance of the EDR special contract.

TERM OF CONTRACT

Service will be furnished under the applicable 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 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. T T T T T T

Solar Share Program Rider

APPLICABLE
In all territory served.

AVAILABILITY T
This optional, voluntary service is available to Customers taking service under Rates RS, RTOD-Energy, RTOD-Demand, VFD, GS, AES, PS, TODS, and TODP. The terms and conditions set out herein are available for and applicable to participation in Company's Solar Share Program. T T

RATE:
A customer may subscribe to capacity in the Solar Share Facilities by paying a One-Time Solar Capacity Charge or a Monthly Solar Capacity Charge—but not both—for each quarter-kW increment subscribed. The customer need not subscribe to all desired capacity using only one subscription approach, but the customer will pay only one kind of charge for each increment of capacity subscribed. For example, a customer subscribing to two quarter-kW increments may pay the One-Time Solar Capacity Charge for one increment and the Monthly Solar Capacity Charge for the other increment. N

One-Time Solar Capacity Charge
A customer subscribing to capacity by paying the One-Time Solar Capacity Charge will receive Solar Energy Credit values subject to the terms and conditions of this Rider for a period of 25 years beginning with and including the first full billing period immediately following the customer's payment in full of the Capacity Charge.

The One-Time Solar Capacity Charge is only available for subscription on Solar Share Facilities that have not begun construction. Any one-time solar capacity subscription that becomes unsubscribed will be made available for subscription under the Monthly Solar Capacity Charge.

One-Time Solar Capacity Charge — $790.00 per quarter-kW subscribed N

Monthly Solar Capacity Charge T
Solar Capacity Charge — $5.68 per quarter-kW subscribed R
D

Solar Energy Credit N
Each billing period during which the Subscriber has paid in full for subscribed capacity under either option above, Company will compare a subscribing customer's pro rata AC energy produced by the Solar Share Facilities (truncated to a whole kWh value) to the subscribing customer's energy consumption (in kWh) every 15 minutes. If consumption exceeded production, Company will bill Customer for the net energy consumed in accordance with Customer's standard rate schedule. If production equaled or exceeded consumption in any relevant period, Company will bill Customer for zero energy consumption for that period and provide a bill credit for each kWh of net production, if any, at the then-applicable non-time-differentiated rate for Company's Standard Rate Rider SQF, (Small Capacity Cogeneration and Small Power Production Qualifying Facilities) Original Sheet No. 55. N N N N N N N N N N N

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Standard Rate Rider **SSP** N

Solar Share Program Rider

PROGRAM DESCRIPTION

The Solar Share Program is an optional, voluntary program that allows customers to subscribe to capacity in the Solar Share Facilities. Each Solar Share Facility will have an approximate direct-current (DC) capacity of 500 kW and will be available for subscription in nominal 250 W (quarter-kW) DC increments. Each subscribing customer ("Subscriber") may subscribe capacity up to an aggregate amount of 500 kW DC, though no Subscriber may subscribe more than 250 kW DC in any single Solar Share Facility.

There are two mutually exclusive options for subscribing to each increment of capacity.

Option 1: Capacity Subscribed by Paying Only the One-Time Solar Capacity Charge

For capacity subscribed by paying the One-Time Solar Capacity Charge, the One-Time Solar Capacity Charge will be included on the Subscriber's bill for the first billing period in which the subscribed capacity achieves commercial operation.

A customer choosing to pay the One-Time Solar Capacity Charge may transfer subscribed capacity between the customer's own accounts or may assign subscribed capacity to another customer. Once assigned, the assigning customer forfeits all rights to the assigned capacity.

A customer who ceases taking service from Company will have 60 calendar days to assign subscribed capacity to another customer within Company's service area. Any capacity such a customer does not assign within 60 days of ceasing to take service will be forfeited and made available to other customers under Option 2: Capacity Subscribed by Paying Only the Monthly Solar Capacity Charge.

Option 2: Capacity Subscribed by Paying Only the Monthly Solar Capacity Charge

For capacity subscribed by paying the Monthly Solar Capacity Charge, the Solar Capacity Charge will be included on the Subscriber's bill beginning with the bill for the first billing period in which the subscribed capacity achieves commercial operation.

Monthly subscriptions of less than 50 kW DC will not require a contract; however, a customer may not reduce or cancel a monthly subscription earlier than 12 months from the date of the customer's most recent change to the customer's monthly subscription level. Therefore, a customer subscribing monthly less than 50 kW has a 12-month commitment from the date of the customer's initial monthly subscription or initial solar facility commercial operation, whichever is later, and may have a longer commitment if the customer subsequently increases monthly subscribed capacity (which a customer may do at any time) or if the customer chooses to decrease but not cancel the monthly subscription after the initial 12 months. Monthly subscriptions of 50 kW DC or more require a 5-year contract with Company.

N

TERMS AND CONDITIONS

1. Individual subscriptions are available in nominal 250 W DC (quarter-kW) increments.

2. Customer may subscribe as much solar capacity as desired up to an aggregate amount of 500 kW DC (nominal). No customer may subscribe more than 250 kW DC (nominal) in any single Solar Share Facility.

3. All One-Time Solar Capacity Charges are non-refundable.

4. Subject to the restrictions above, Company will fill subscriptions as capacity in the Solar Share Facilities becomes available, and will fill subscriptions in the chronological order in which the subscriptions were made. A Subscriber whose subscription the Company can fulfill only partially may either accept the available capacity and await additional capacity, or decline the partial fulfillment, allowing the next awaiting Subscriber(s) to accept the available capacity. Accepting or declining available capacity will not affect a Subscriber's place in the queue of Subscribers awaiting capacity.

5. Customers may not owe any arrearage prior to participating in the Solar Share Program.

6. Subscribers' pro-rata share of the AC electricity produced by the Solar Share Facilities will be determined on a billing-cycle basis. The corresponding Solar Energy Credit will be calculated and appear on the Subscriber's bill.

7. Unless constrained by contract (see Term of Contract below), Subscriber may decrease or terminate a monthly subscription any time after 12 months following the date of the most recent change to Subscriber's monthly subscription capacity at any time.

8. Unless constrained by contract (see Term of Contract below) or condition #2 above, Subscriber may also increase monthly subscribed capacity at any time.

9. Subscriptions made by paying the One-Time Solar Capacity Charge may be transferred between a Subscriber's accounts no more than once per billing period (Solar Energy Credit values do not transfer between accounts or customers). A subscription transfer between a Subscriber's accounts takes effect in the billing period following the billing period in which the Subscriber requests the transfer. A Subscriber may transfer a subscription at any time prior to or including 60 calendar days after the Subscriber terminated service on the account to which the subscription attached. If the Subscriber whose account has been terminated does not transfer the subscription within 60 calendar days, the Subscriber forfeits the subscription.

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TERMS AND CONDITIONS (continued)

10. Capacity subscribed by paying the Monthly Solar Capacity Charge is not transferrable or assignable between customers.

11. Capacity subscribed by paying the One-Time Solar Capacity Charge may be assigned between customers, but only within the same Company service territory, at any time prior to or including 60 calendar days after the assigning Subscriber terminated service on the account to which the subscription attached. Once assigned, the assigning customer loses all rights regarding future credits and the ability to subsequently assign the capacity; those rights become the rights of the assignee upon assignment. Assigned capacity cannot be reassigned by the assignee to any other Customer, including the Customer who originally subscribed the assigned capacity. For all purposes other than the Solar Energy Credit, all capacity assignments become effective immediately upon assignment. For the purpose of the Solar Energy Credit, the assignor will receive Solar Energy Credits for the entire billing period in which the assignment occurs; the assignee will receive Solar Energy Credits beginning in the first billing period following the assignment.

12. Unused Solar Energy Credit value is not transferrable between customers or customer accounts. Therefore, a Subscriber’s closing a customer account terminates any unused Solar Energy Credit value associated with that account.

13. Participants in SSP are required to have an advanced meter capable of collecting and communicating at least 15 minute interval data.

14. All Renewable Energy Credits (“RECs”) related to energy produced by subscribed portions of the Solar Share Facilities will be retired.

15. Use of any images of the Solar Share Facilities or use any other of Company’s intellectual property requires Company licensing prior to use.

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

TERM OF CONTRACT

Subscriptions of 50 kW DC or more will require a five (5) year non-transferrable, non-assignable contract between Subscriber and Company.

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Standard Rate Rider **EVSE-R**

Electric Vehicle Supply Equipment

APPLICABLE

In all territory served.

AVAILABILITY T

Available as a rider to Customers to be served or currently being served under Rates GS (with energy usage of 500 kWh or higher per month), AES, PS, TODS, TODP, RTS, and FLS for the purpose of charging electrical vehicles, whereby Customer installs and owns facilities on its side of the point of delivery of the energy supplied hereunder necessary to serve Company-provided charging station. T T

Charging station under this rider is offered under the conditions set out hereinafter for electric vehicle supply equipment such as, but not limited to, the charging of electric vehicles via street parking, parking lots, and other outdoor areas. Customer is responsible for providing the appropriate voltage levels and connections necessary to operate Company-provided charger.

Company will coordinate charging station installation with Company's current charging station supplier and Customer. Customer shall be responsible for the charging equipment installation costs. T T

Service will be provided under written contract, signed by Customer prior to service commencing.

RATE	Single Charger	Dual Charger	
Monthly Charging Unit Fee:	$123.99	$175.95	R/R

ADJUSTMENT CLAUSES

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

Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

PAYMENT

The EVSE-R charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

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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. Cancellation by Customer prior to the expiration of the initial term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the initial term of the contract.

TERMS AND CONDITIONS

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

2. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for installation.

3. 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 and/or equipment is made to Company facilities, Customer must have an attachment agreement with Company.

4. 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.

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

6. If Customer requests the removal of an existing charging station, including, but not limited to, poles, or other supporting facilities that were in service less than twenty (20) years, and requests T installation of replacement facilities within five (5) years of removal, Customer agrees to pay to T Company its cost of labor to install the replacement facilities.

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

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8. 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.

9. Notwithstanding the provisions of 807 KAR 5:006, Section 14(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 service shall furnish Company with realistic estimates of prospective electricity requirements.

10. Customer shall agree to permit Company to obtain specific charging station usage data directly from the Charging Station Supplier.

MINIMUM CHARGE

As determined by this rider and the rate schedule to which it is attached.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 81

Standard Rate Pilot **OSL** T

Outdoor Sports Lighting Service T

APPLICABLE

In all territory served.

AVAILABILITY T

Available as an optional pilot program for secondary and primary service used by a Customer for lighting specifically designed for outdoor fields which are normally used for organized competitive sports. Service under this rate schedule is limited to a maximum of twenty Customers. Company will accept Customers on a first-come-first-served basis. T

RATE

	Secondary	Primary	
Basic Service Charge per day:	$2.96	$7.89	T/I
Plus an Energy Charge per kWh of:	$0.03270	$0.03189	R
Plus a Maximum Load Charge per kW of:			
Peak Demand Period	$19.42	$19.57	I
Base Demand Period	$3.03	$2.87	R

Where:

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

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

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

1. the maximum measured load in the billing period, or T
2. the highest measured load in the preceding eleven (11) monthly billing periods, or T
3. if applicable, the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. T

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	T
Franchise Fee	Sheet No. 90	D/T
School Tax	Sheet No. 91	

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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.

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	Peak
Weekdays	All Hours	1 P.M. – 7 P.M.
Weekends	All Hours	

All other months of October continuously through April

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

If a legal holiday falls on a weekday, it will be considered a weekday. N

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT
Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party ninety (90) days prior to termination. Company, however, may require a longer T 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.

Fuel Adjustment Clause

APPLICABLE

In all territory served.

AVAILABILITY T

This schedule is mandatory to all rate schedules. T

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.

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).

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 August 2015, and the base fuel factor is $0.02609 per kWh.

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

Demand-Side Management Cost Recovery Mechanism

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

RATE

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

DSMRC = DCR + DRLS + DSMI + DBA + DCCR

Where:

DCR = DSM COST RECOVERY

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

DRLS = DSM REVENUE FROM LOST SALES

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

Demand-Side Management Cost Recovery Mechanism

RATE (continued)

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, Residential Time-of-Day Energy Service, Volunteer Fire Department, General Service, and All Electric School customer classes is defined as the weighted average price per kWh of expected billings under the energy charges contained in the RS, RTOD-Energy, VFD, GS, and AES 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 RTOD-Demand, PS, TODS, TODP, RTS, and OSL) 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

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

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

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

DSMI = DSM INCENTIVE

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

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

DBA = DSM BALANCE ADJUSTMENT

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

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

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

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

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

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

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

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

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

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

PROGRAMMATIC CUSTOMER CHARGES

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

Residential Load Management / Demand Conservation
The Residential Load Management / Demand Conservation Program employs 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. For on-site audits conducted prior to April 1, 2018, customers are eligible for incentives of $150 or $1,000 based on customer purchased and installed energy efficiency measures and validated through a follow-up test. The follow-up test must be scheduled by September 1, 2018. No follow-up tests or incentives will be available related to on-site audits conducted on or after April 1, 2018.

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, and blower door tests, and installs weatherization and energy conservation measures. Qualified customers could receive energy conservation measures ranging from $0 to $2,100 based upon the customer's most recent twelve month energy usage and results of an energy audit.

Smart Energy Profile
The Smart Energy Profile Program provides a portion of KU's highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar local properties. 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. The Company will cease offering this program effective April 1, 2018.

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. The Company will cease offering this program effective April 1, 2018. All incentives will go to $0 at that time. A customer desiring an incentive must purchase a qualified item and request an application from the Company prior to April 1, 2018. All incentive applications, including proofs of purchase, must be received by September 1, 2018.

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

Residential Refrigerator Removal Program

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

Customer Education and Public Information

This program helps 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 three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. 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. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Residential Advanced Metering Systems Incentives:
The following Demand Side Management offering is available to residential customers receiving service from the Company on the RS Rate Schedule.

Advanced Metering Systems
The Advanced Metering Systems offering is designed to provide energy consumption data to customers on a more frequent basis than is traditionally available through monthly billing. The Program employs advanced meters to communicate hourly consumption data to customers through a website.

Commercial Customer Program Participation Incentives:
The following Demand Side Management programs are available to commercial customers receiving service from the Company on the GS, AES, PS, TODS, TODP, RTS, and OSL 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 86.9.

Commercial Conservation / Commercial Incentives
The Commercial Conservation / Commercial Incentive Program is designed to increase the implementation of energy efficiency measures by providing financial incentives to assist with the replacement of aging and less efficient equipment and for new construction built beyond code requirements. The Program also offers an online tool providing recommendations for energy-efficiency improvements. Incentives available to all commercial customers are based upon a $100 per kW removed for calculated efficiency improvements completed by March 31, 2018. Effective April 1, 2018, the incentives will be based upon a $0.03 per kWh of energy saved for calculated efficiency improvements. A prescriptive list provides customers with incentive values for various efficiency improvement projects. Additionally, a custom rebate is available based upon company engineering validation of sustainable energy savings. New construction rebates are available on savings over code plus bonus rebates for LEED certification.

- 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, Custom and New Construction Rebates

Customer Education and Public Information
This program helps 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 three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. 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. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

School Energy Management Program
The School Energy Management program will facilitate the hiring and retention of qualified, trained energy specialists by public school districts to support facilitation of energy efficiency measures for public and independent schools under KRS 160.325.

Commercial Advanced Metering Systems Incentives:
The following Demand Side Management offering is available to residential customers receiving service from the Company on the GS Rate Schedule.

Advanced Metering Systems
The Advanced Metering Systems offering is designed to provide energy consumption data to customers on a more frequent basis than is traditionally available through monthly billing. The Program employs advanced meters to communicate hourly consumption data to customers through a website.

Current Program Incentive Structures

Residential Load Management / Demand Conservation

Switch Option:

- $3/month bill credit for June, July, August, and September per air conditioning unit or heat pump on single family home.
- $2/month bill credit for June, July, August, and September per electric water heater (40 gallon minimum) or swimming pool pump on single family home.

Multi-family Option:

- Tenant - $2/month bill credit per customer for June, July, August, and September per air conditioning unit or heat pump.

Residential Refrigerator Removal Program
The program provides $50 per working refrigerator or freezer.

Commercial Load Management / Demand Conservation

Switch Option

- $3 per month bill credit for June, July, August, and September for air conditioning units up to 5 tons.

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.

- $15 per kW for verified load reduction during June, July, August, and September.
- The customer will have access to at least hourly load data for every month of the year which they remain enrolled in the program.
- Additional customer charges may be incurred for metering equipment necessary for this program at costs under other tariffs.

Kentucky Utilities Company

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day Demand Service Rate RTOD-Demand, and Volunteer Fire Department Service Rate VFD	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00155 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00012 per kWh
DSM Incentive (DSMI)	$ 0.00002 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00063 per kWh
DSM Balance Adjustment (DBA)	$ 0.00011 per kWh
Total DSMRC for Rates RS, RTOD-Energy, RTOD-Demand, and VFD	$ 0.00243 per kWh

General Service Rate GS*	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00097 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00027 per kWh
DSM Incentive (DSMI)	$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00013 per kWh
DSM Balance Adjustment (DBA)	$ 0.00020 per kWh
Total DSMRC for Rate GS	$ 0.00158 per kWh

All Electric School Rate AES	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00031 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00008 per kWh
DSM Incentive (DSMI)	$ 0.00000 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00040 per kWh
DSM Balance Adjustment (DBA)	$ 0.00000 per kWh
Total DSMRC for Rate AES	$ 0.00079 per kWh

Power Service Rate PS*, Time of Day Secondary Service Rate TODS*, Time-of-Day Primary Service Rate TODP*, Retail Transmission Service Rate RTS*, and Outdoor Sports Lighting Service Rate OSL	Energy Charge	
		T
DSM Cost Recovery Component (DCR)	$ 0.00028 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00009 per kWh	
DSM Incentive (DSMI)	$ 0.00000 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00016 per kWh	
DSM Balance Adjustment (DBA)	$(0.00003) per kWh	
Total DSMRC for Rates PS, TODS, TODP, RTS, and OSL	$ 0.00050 per kWh	T

* These charges do not apply to industrial customers taking service under these rates because the Company currently does not offer industrial DSM programs.

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Adjustment Clause **ECR**

Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY T

This schedule is mandatory to all rate schedules listed in Section 1 of the General Index except Rate PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and FAC (including OSS) and DSM Adjustment Clauses. Rate schedules subject to this adjustment clause are divided into Group 1 or Group 2 as follows: T T T T

Group 1: Rates RS; RTOD-Energy; RTOD-Demand; VFD; AES; LS; RLS; LE; and TE. T
Group 2: Rates GS; PS; TODS; TODP; RTS; FLS; EVSE; EVC; and OSL. 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 twelve (12) month average revenue for the current expense month and for Group 2 it is the twelve (12) month average non-fuel revenue for the current expense month. T T

DEFINITIONS

1. For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – EAS + 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. OE includes operation and maintenance expense recovery authorized by the K.P.S.C. in all approved ECR Plan proceedings.
   f. EAS is the total proceeds from emission allowance sales.
   g. BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse.
   h. Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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DEFINITIONS (continued)

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 twelve (12) months ending with T 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 twelve (12) T months ending with the current expense month. Base revenue includes 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 twelve T (12) months ending with the current expense month. Base non-fuel revenue includes T 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.

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State Regulation and Rates
Lexington, Kentucky

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Adjustment Clause **OSS**

Off-System Sales Adjustment Clause

APPLICABLE.
In all territory served.

AVAILABILITY T
Mandatory to all rate schedules that are subject to Adjustment Clause FAC. T

RATE

The monthly OSS Adjustment Factor per kWh delivered under each of the schedules to which this mechanism is applicable shall be calculated in accordance with the following formula:

OSS Adjustment Factor = 0.75 x [(P(m) / S(m)]

Where "P" is the net eligible margins from off-system power sales and "S" is the kWh sales in the current period (m) as defined in 807 KAR 5:056. The OSS Adjustment Factor will be applied as set out below.

1. The monthly OSS Adjustment Factor will be combined with the monthly FAC factor and billed as one.

2. Current expense month (m) shall be the second month preceding the month in which the combined FAC and OSS factor is billed.

3. The combined monthly FAC and OSS factor shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Adjustment Clause **FF**

Franchise Fee T

APPLICABLE

In all territory served.

AVAILABILITY T

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 rate schedules. T

BILLING T

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 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.
4. At its option, a governmental body imposing a franchise fee shall not be billed for that portion of a franchise fee, applied to services designated by the governmental body that would ultimately be repaid to the governmental body.

TERM OF CONTRACT

As agreed to in the franchise agreement. Company will not calculate or collect any such fees, taxes, or charges pursuant to expired, lapsed, or otherwise invalid, ineffective or inapplicable ordinances, franchise agreements, or other governmental enactment. T T T

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

SECTIONS APPLICABLE ONLY TO FRANCHISE FEE AGREEMENTS DATED BEFORE September 21, 2011 N T

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.

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.

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On and After August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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

Home Energy Assistance Program

APPLICABLE
In all territory served.

AVAILABILITY
To all residential Customers.

RATE
$0.30 per month.

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

PURPOSE
Proceeds from this charge will be used to fund residential low-income Home Energy Assistance T
programs, which have been designed through a collaborative advisory process and approved by T
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, unless any rate or rider under which you take service explicitly states otherwise.
- 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).

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On and After July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00370 dated June 22, 2017 and modified June 29, 2017

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 Kentucky Public Service Commission.

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 to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions in each rate schedule, and which shall constitute a part of all applications and contracts for service.

COMPANY AS A FEDERAL CONTRACTOR

The United Nations Convention on Contracts for the International Sale of Goods is specifically disclaimed and excluded and will not apply to or govern agreements between Customers and Company.

To the extent Company is a federal contractor, Company and its subcontractors shall abide by the requirements of 41 CFR 60-741.5(a). This regulation prohibits discrimination against qualified individuals on the basis of disability, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified individuals with disabilities.

To the extent Company is a federal contractor, Company and its subcontractors shall abide by the requirements of 41 CFR 60-300.5(a). This regulation prohibits discrimination against qualified protected veterans, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified protected veterans.

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 Kentucky Public Service Commission. 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.

CUSTOMER GENERATION

All existing and future installations of equipment for the purpose of electric generation that is intended to run in parallel with utility service, regardless of the length of parallel operation, shall be reported by Customer (or Customer's Representative) to Company in conjunction with the "Notice to Company of Changes in Customer's Load" set out in Customer Responsibilities section of the Terms and Conditions of Company's Tariff.

ASSIGNMENT

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

Terms and Conditions
General

RENEWAL OF CONTRACT

If, upon the expiration of any service contract for a specified term, 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: September 28, 2018

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On and After July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Terms and Conditions
Customer Responsibilities

APPLICATION FOR SERVICE

A written, in-person, electronic, or oral application or contract, properly executed, will be required before Company is obligated to render electric service. Company may require any party applying for service to provide some or all of the following information for the party desiring service: full legal name, address, full Social Security Number or other taxpayer identification number, date of birth (if applicable), relationship of the applying party to the party desiring service, and any other information Company deems necessary for legal, business, or debt-collection purposes. Company shall have the right to reject for valid reasons any such application or contract, including the applying party's refusal to provide requested information.

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 rate schedules, T
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.

If Company or Customer terminates Customer's service under a rate schedule that contains demand charges and Customer subsequently applies to Company to reestablish service to the same premise or facility, Company must determine monthly billing demand for the reestablished service as though Customer had continuously taken service from the time of service termination through the reestablishing of service to Customer. For the purpose of determining the monthly billing demand described in the preceding sentence, the demand to be used for the period during which Customer did not take service from Company shall be the actually recorded demand, if any, for the premise or facility during that period. The preceding two sentences will not apply if Company determines, in its sole discretion, that material changes to Customer's facilities, processes, or practices justify establishing a new Contract Demand for the reestablished service.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Terms and Conditions
Customer Responsibilities

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 (12) 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 Customer will at all times be served under the most beneficial rate.

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

CUSTOMER'S EQUIPMENT AND INSTALLATION

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

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

OWNER'S CONSENT TO OCCUPY

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

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State Regulation and Rates
Lexington, Kentucky

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Terms and Conditions
Customer Responsibilities

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.

POWER FACTOR

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

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

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

Terms and Conditions
Customer Responsibilities

NOTICE TO COMPANY OF CHANGES IN CUSTOMER'S LOAD

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

PERMITS

Customer shall obtain or cause to be obtained all permits, easements, or certificates, except street permits, necessary to give Company or its agent 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 all such wiring or other Customer-owned electrical equipment as may be necessary or convenient for the supply of electric service to Customer. Provided, however, to the extent permits, easements, or certificates are necessary for the installation and maintenance of Company-owned facilities, Company shall obtain the aforementioned consent.

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

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

CHANGES IN SERVICE

Where Customer is receiving service and desires relocation or change in facilities not supported by additional load, Customer is responsible for the cost of the relocation or change in facilities through a Non-Refundable Advance.

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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. Company has the right to install any meter or meters it deems in its sole discretion to be necessary or prudent to serve any Customer, including without limitation a digital, automated meter reading, automated metering infrastructure, or advanced metering systems meter or 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 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.

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Terms and Conditions
Company Responsibilities

Notwithstanding the provisions of 807 KAR 5:006, Section 14(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.

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

Where a Customer-generator supplies all or part of Customer-generator's own load and desires Company to provide service for that load, Customer-generator must contract for such service, otherwise Company has no obligation to supply the non-firm service.

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Terms and Conditions
Character of Service

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

SECONDARY VOLTAGES

Residential Service -

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

Non-Residential Service -

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

PRIMARY VOLTAGES

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

TRANSMISSION VOLTAGES

According to location, 69,000 volts, 138,000 volts, 161,000 volts, or 345,000 volts. T

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

RESTRICTIONS

1. Except for minor loads, with approval of Company, two-wire service is restricted to those Customers on service July 1, 2004.
2. To be eligible for the rate applicable to any delivery voltage other than secondary voltage, Customer must furnish and maintain complete substation structure, transformers, and other equipment necessary to take service at the primary or transmission voltage available at point of connection.

   a. In the event Company is required to provide transformation to reduce an available voltage to a lower voltage for delivery to a Customer, Customer shall be served at the rate applicable to the lower voltage; provided, however, that if the same rate is applicable to both the available voltage and the delivery voltage, Customer may be required to make a non-refundable payment to reflect the additional investment required to provide service.

   b. The available voltage shall be the voltage on that distribution or transmission line which Company designates as being suitable from the standpoint of capacity and other operating characteristics for supplying the requirements of Customer.

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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. **DEFINITION OF RESIDENTIAL RATE** - Residential rates are based on service to single family units served through a single meter. Such service may include incidental usage of electricity for home occupations, such as the office of a physician, surgeon, dentist, musician or artist when such occupation is practiced by Customer in Customer's residence. Service to both a single family unit and a detached structure may both be served through a single meter, regardless of the meter location, and qualify for the residential service provided the consumption in the non-residential portion of the detached structure is incidental.

2. **DEFINITION OF SINGLE FAMILY UNIT** - A single family unit is a structure or part of a structure used or intended to be used as a home, residence, or sleeping place by one or more persons maintaining a common household. Residential service is not available to transient multi-family structures including, but not limited to, hotels, motels, studio apartments, college dormitories, or any structure without a permanent foundation or attached to sanitation facilities. Fraternity or sorority organizations associated with educational institutions may be classified as residential and billed at the residential rate.

3. **DETACHED STRUCTURES** - If Customer has detached structures that are located at such distance from Customer's residence as to make it impracticable to supply service through Customer's residential meter, the separate meter required to measure service to the detached structures will be considered a separate service and billed as a separate Customer.

4. **POWER REQUIREMENT -** Single-phase power service used for domestic purposes will be permitted under Residential Rates RS, RTOD-Energy, and RTOD-Demand when measured through the residential meter subject to the conditions set forth below:

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

   b. Single-phase motors of new central residential cooling installations with total locked-rotor ratings of not to exceed 125 amperes (inclusive of any auxiliary motors arranged for simultaneous starting with the compressor) may be connected for across-the-line starting provided the available capacity of Company's electric distribution facilities at desired point of supply is such that, in Company's judgment, the starting of such motors will not result in excessive voltage dips and undue disturbance of lighting service and television reception of

Terms and Conditions
Residential Rate Specific Terms and Conditions

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

As used in the entirety of this Tariff, “meter reading” and similar terms shall include data collected remotely from automated meter reading, automated meter infrastructure, advanced metering systems, and other electronic meter equipment or systems capable of delivering usage data to Company. A physical, manual reading of a meter is not required to constitute a “meter reading.”

Each bill for utility service shall be issued in compliance with 807 KAR 5:006, Section 7.

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’s 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 (30) days, unless an applicable rate schedule has a daily Basic Service Charge, in which case a full daily N
Basic Service Charge will be charged to a customer for each day or partial day during which the N
customer’s account was open and served under that rate schedule. N

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

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

Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within sixteen (16) business days (no less than twenty-two (22) calendar days) from date of rendition thereof. If full payment is not received by 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 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 Company receives Customer’s payment within fifteen (15) days after the date on which Company issues Customer’s bill.

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

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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 (2) or more meters will not be combined except where Company's operating convenience requires the installation of two (2) or more meters upon Customer's premises instead of one (1) meter.

CUSTOMER RATE ASSIGNMENT

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.

Terms and Conditions
Billing

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

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."

Terms and Conditions
Billing

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 quarterly. In addition, Company may investigate usage deviations brought to its attention as a result of its ongoing meter reading or billing processor Customer inquiry. Should an unusual deviation in Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of Customer's meter reading and billing records, Company may contact Customer to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether the results show the meter is within the limits allowed by 807 KAR 5:041, Section 17(1). Company will notify Customer of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 11(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 Basic Service Charge and Demand Charge shall apply and be T
due for all times during which a customer's account is open, regardless of any event or T
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 8, except for Customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, 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 six (6) 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 Rates RS - Sheet No. 5, RTOD-Energy - Sheet No. 6, and RTOD-Demand - Sheet No. 7.
2. The deposit for a residential Customer is in the amount of $160.00, which is calculated in accordance with 807 KAR 5:006, Section 8(1)(d)(2).
3. Company will retain Customer’s deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.
4. If a deposit is held longer than eighteen (18) months, the deposit will be recalculated at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.

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Terms and Conditions
Deposits

RESIDENTIAL (Continued)

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.

GENERAL SERVICE

1. General service Customers are those Customers served under General Service Rate GS, Sheet No. 10.
2. The deposit for a general service Customer is in the amount of $240.00, which is calculated in accordance with 807 KAR 5:006, Section 8(1)(d)(2). The deposit for a General Service Customer may be waived when the General Service delivery is to a detached building used in conjunction with a Residential Service and the General Service usage is no more than 300 kWh per month.
3. Company shall retain Customer's deposit as long as Customer remains on service.
4. For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten (10%) percent, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5. If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1. The deposit for all other Customers, those not classified herein as residential or general service, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR 5:006, Section 8(1)(d)(1).
2. For Customers not meeting the parameters of GENERAL SERVICE ¶ 2, above, Company may retain Customer's deposit as long as Customer remains on service.
3. For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten (10%) percent, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4. If Customer fails to maintain a satisfactory payment or credit record, or otherwise become a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

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Terms and Conditions
Budget Payment Plan

Company's Budget Payment Plan is available to any residential Customer served under Residential Service Rate RS or any general service Customer served under General Service Rate GS. If a residential Customer, who is currently served under Residential Service Rate RS and is currently enrolled in the Budget Payment Plan, elects to take service under Residential Time-of-Day Energy Service Rate RTOD-Energy or Residential Time-of-Day Demand Service Rate RTOD-Demand, such Customer would be removed from the Budget Payment Plan and restored to regular billing.

Under this plan, a Customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A Customer may enroll in this plan at any time.

The budgeted amount will be determined by Company and will be based on one-twelfth of Customer's usage for either an actual or estimated twelve (12) months. The budgeted amount will be subject to review and adjustment by Company at any time during Customer's budget year. If actual usage indicates Customer's account will not be current with the final payment in Customer's budget year, Customer will be required to pay their Budget Payment Plan account to $0 prior to the beginning of 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 Customer from the plan, restore the Customer to regular billing, and require immediate payment of any deficiency. A Customer removed from the Budget Payment Plan for non-payment may be prohibited from further participation in the plan for twelve (12) months.

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

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Terms and Conditions

Bill Format

Mailed **9/17/18** for Account # **3000-0000-0004**

AMOUNT DUE **$131.80** **DUE DATE** **10/11/18**

a PPL company

BILLING SUMMARY

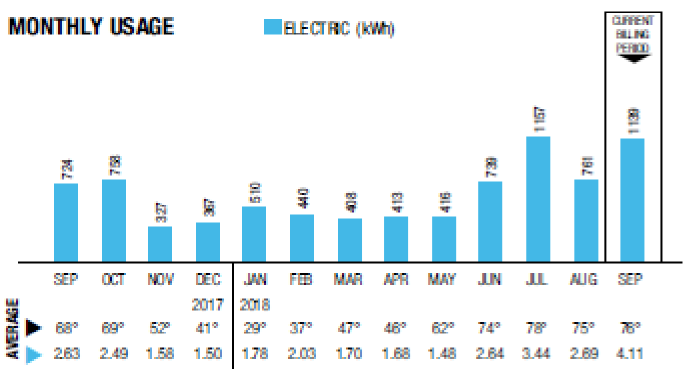
Previous Balance	83.48
Payment(s) Received	-83.48
Balance as of 9/14/18	**$0.00**
Current Electric Charges	123.19
Current Taxes and Fees	8.61
Total Current Charges as of 9/14/18	**$131.80**
Total Amount Due	**$131.80**

Account Name:	JANE DOE
Service Address:	220 W Main St LEXINGTON KY
Online Payments:	lge-ku.com
Telephone Payments:	(859) 255-0394, press 1-2-3 24 hours a day; $2.00 fee
Customer Service:	(859) 255-0394 M-F, 7am-7pm ET
Walk-in Center:	1 Quality Street Lexington, KY 40507 M-F, 8am-5pm ET

Next read will occur 10/15/18 - 10/17/18 (Meter Read Portion 10)

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	76°	68°
Number of Days Billed	30	30
Avg. Electric Charges per Day	$4.11	$2.63
Avg. Electric Usage per Day (kWh)	37.97	24.13



Please return only this portion with your payment. Make checks payable to KU and write your account number on your check.

Amount Due 10/11/18	**$131.80**
After Due Date, Pay this Amount:	**$135.75**
WinterCare Donation:	
Total Amount Enclosed:	**AUTOPAY**

$131.80 will be deducted from your account on payment due date

Account # **3000-0000-0004**
Service Address: 220 W Main St

#9160900041#

JANE DOE
220 W MAIN ST
LEXINGTON, KY 40514-1000

a PPL company
PO Box 25212
Lehigh Valley, PA 18002-5212

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 104.1

Terms and Conditions T
Bill Format

Page 2 Account # **3000-0000-0004**

CURRENT USAGE

ELECTRIC

Meter Reading Information	**Meter # 7000000**
Actual (R) kWh Reading on 9/14/18	14671
Actual (R) kWh Reading on 8/15/18	13532
Current kWh Usage	1139
Meter Multiplier	1
Metered kWh Usage	**1139**

CURRENT CHARGES

ELECTRIC	**Rate:** Residential Service
Basic Service Charge ($0.53 x 30 days)	15.90
Energy Charge ($0.09552 x 1139 kWh)	108.80
Electric DSM ($0.00243 x 1139 kWh)	2.77
Fuel Adjustment ($-0.00303 x 1139 kWh)	-3.45
Environmental Surcharge (0.910% CR x $124.02)	-1.13
Home Energy Assistance Fund Charge	0.30
Total Charges	**$123.19**

Taxes & Fees	
Rate Increase For School Tax (3.00% x $122.89)	3.64
Franchise Fee-Lexington-Fayette (4.00% x $122.89)	4.86
Total Taxes and Fees	**$8.61**

BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $3.95

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

NATIONAL PREPAREDNESS MONTH

DISASTERS HAPPEN. PREPARE NOW. LEARN HOW.
lge-ku.com/safety/preparedness

OFFICE USE ONLY:
MRU10311510, G000000
P83.48
PF:Y eB:P

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Terms and Conditions

Discontinuance of Service

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

1. 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 or otherwise delivered, including, but not limited to, electronic mail, to Customer’s last known address.

2. 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.

3. When Customer or Applicant refuses or neglects to provide reasonable access and/or easements to and on Customer’s or Applicant’s 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 (either mailed or otherwise delivered, including, but not limited to, electronic mail) of Company's intention to discontinue or refuse service.

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

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

6. When directed to do so by governmental authority.

7. 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 15(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 15(1)(f). Final Bills transferred following a

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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.

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.

8. 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 Customer's 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 (either mailed or otherwise delivered, including, but not limited to, electronic mail), of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance.

9. For fraudulent or illegal use of service. When Company discovers evidence that by fraudulent or illegal means Customer has obtained unauthorized service or has diverted the service for unauthorized use or has obtained service without same being properly measured, the service to Customer may be discontinued without notice. Within twenty-four (24) hours after such termination, Company shall send written notification to Customer of the reasons for such discontinuance of service and of Customer's right to challenge the termination by filing a formal complaint with the Kentucky Public Service Commission. 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.

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Terms and Conditions
Discontinuance 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 assessment of the charges under the Unauthorized Reconnect Charge provision of Special Charges 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 (either mailed or otherwise delivered, including, but not limited to, electronic mail) based on Customer's payment history provided Company continues to provide the required ten (10) days written notice prior to discontinuance of service.

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Terms and Conditions
Line Extension Plan

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

2. **DEFINITIONS** T
   a "Company" shall mean Kentucky Utilities Company. T
   b. "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. T T
   c. "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. T
   d. "Permanent Service" shall mean service contracted for under the terms of the applicable rate schedule but not less than one (1) year and where the intended use is not seasonal, intermittent, or speculative in nature. T
   e. "Commission" shall mean the Kentucky Public Service Commission. T

3. **GENERAL** T
   a. All extensions of service will be made through the use of overhead facilities except as provided in these rules. T
   b. 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. T
   c. 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. T
   d. The title to all extensions, rights-of way, permits, and easements shall be and remain with Company. T

Terms and Conditions
Line Extension Plan

3. GENERAL (continued) T
e. Customer must agree in writing to take service when the extension is completed and have T
Customer's building or other permanent facility wired and ready for connection.
f. Nothing herein shall be construed as preventing Company from making electric line extensions T
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
feasible the capital expenditure involved and provided such extensions are made to other
Customers under similar conditions.
g. Company may require a non-refundable deposit in cases where Customer does not have a T
real need or in cases where the estimated revenue does not justify the investment.
h. Company shall not be obligated to extend its lines in cases where such extensions, in the good T
judgment of Company, would be infeasible, impractical, or contrary to good engineering or
operating practice, unless otherwise ordered by Commission.

4. NORMAL LINE EXTENSIONS T
a. In accordance with 807 KAR 5:041, Section 11(1), Company will provide, at no cost, a line T
extension of up to 1,000 feet to Customer requesting permanent service where the installed
transformer capacity does not exceed 25 kVA.
b. Where Customer requires poly-phase distribution service or transformer capacity in excess T
of 25 kVA and Company provides such facilities, Company shall provide at its own expense N
the requested line extension, but only to the extent that the cost of the requested extension N
does not exceed the lesser of (i) the cost of a comparable overhead extension (if an N
underground extension is requested) or (ii) five (5) times Customer's estimated annual net N
revenue, where "net revenue" is defined as Customer's total revenue less base fuel, Fuel N
Adjustment Clause, Off-System Sales, Demand Side Management, franchise fees, and N
school taxes. Company may require Customer to pay in advance a non-refundable amount N
for the additional cost above the five (5) times net revenue calculation to Company in T
providing facilities above that required in NORMAL LINE EXTENSIONS ¶ a. above. T
Customer must commit to a minimum contract term of five (5) years. N

5. OTHER LINE EXTENSIONS T
a. In accordance with 807 KAR 5:041, Section 11(2), Company shall provide to Customer T
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.
b. After the ten (10) year period following the line extension, Company shall refund to Customer, T
who made the deposit for excess footage, the cost of 1,000 feet of extension for each additional
Customer connected during the first ten (10) year period directly to the original extension for T
which the deposit was made.
c. After the ten (10) year period following the line extension, Company shall refund to Customer, T
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 the first ten (10) year T
period by a lateral or extension to the original extension for which the deposit was made. T
d. The total amount refunded shall not exceed the amount originally deposited nor shall any T
refund be made after the ten (10) year refund period ends.

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Terms and Conditions
Line Extension Plan

5. OTHER LINE EXTENSIONS (continued)

e. Where Customer requires poly-phase distribution service or transformer capacity in excess T
of 25 kVA and Company provides such facilities, Company shall provide at its own expense T
the requested line extension, but only to the extent that the cost of the requested extension N
does not exceed the lesser of (i) the cost of a comparable overhead extension (if an N
underground extension is requested) or (ii) five (5) times Customer's estimated annual net N
revenue, where "net revenue" is defined as Customer's total revenue less base fuel, Fuel N
Adjustment Clause, Demand Side Management, franchise fees, and school taxes. Company N
may require Customer to pay in advance a non-refundable amount for the additional cost N
above the five (5) times net revenue calculation to Company in providing facilities above that N
required in NORMAL LINE EXTENSIONS ¶ a. above. N

6. OVERHEAD LINE EXTENSIONS FOR SUBDIVISIONS T

a. In accordance with 807 KAR 5:041, Section 11(3), Customer desiring service extended for and T
through a subdivision may be required by Company to deposit the total cost of the extension.

b. After the ten (10) year period following the line extension, Company shall refund to Customer, T
the cost of 1,000 feet of extension for each additional Customer connected during the first ten T
(10) year period directly to the original extension for which the deposit was made. T

c. The total amount refunded shall not exceed the amount originally deposited nor shall any T
refund be made after the ten (10) year refund period ends.

7. MOBILE HOME LINE EXTENSIONS T

a. Company will make line extensions for service to mobile homes in accordance with 807 KAR T
5:041, Section 12, and Commission's Orders.

b. Company shall provide, at no cost, a line extension of up to 300 feet to Customer requesting T
permanent service for a mobile home.

c. Company shall provide to Customer requesting permanent service for a mobile home a line T
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.

d. Each year for four (4) years Company shall refund to Customer equal amounts of the deposit T
for the extension from 300 feet to 1,000 feet.

e. If service is disconnected for sixty (60) days, if the original mobile home is removed and not T
replaced by another mobile home or a permanent structure in sixty (60) days, the remainder of
the deposit is forfeited.

f. No refund will be made except to the original Customer. T

8. UNDERGROUND LINE EXTENSIONS T

a. General T

i. Company will make underground line extensions for service to new residential T
Customers and subdivisions in accordance with 807 KAR 5:041, Section 21.

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Terms and Conditions
Line Extension Plan

8. UNDERGROUND LINE EXTENSIONS T

General (continued) T

ii. 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. T T

iii. 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. T

iv. 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. T

v. Customer will provide, own, operate and maintain all electric facilities on Customer's side of the point of delivery with the exception of Company's meter. T

D

vii. 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. T

viii. 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. T

b. Individual Premises T

Where Customer requests and Company agrees to supply underground service (primary) to an individual premise, Company may require Customer to furnish ditching, conduit, backfill, and transformer pad. Company will then use overhead extension policy requirements. T N N

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c. Medium Density Subdivisions T

i. 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. T

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Terms and Conditions
Line Extension Plan

8. **UNDERGROUND EXTENSIONS** T
   c. **Medium Density Subdivisions** (continued) T
      ii. 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 $10.10 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension. T

      iii. Customer may be required to advance to 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 Company's full estimate cost of construction. Where Customer is required to deposit with Company a non-refundable advance in place of trenching and backfilling, advance will be determined by a unit charge of $22.09 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension. T

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

      v. 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 (10) year refund period ends. T

   d. **High Density Subdivisions** T
      i. 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. T
      ii. 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. T
      iii. Customer may be required to advance to Company's full estimated cost of construction of an underground electric distribution extension. T

d. High Density Subdivisions (continued) T

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 (10) year refund period ends.

e. Other Underground Subdivisions T
In cases where a particular residential subdivision does not meet the conditions provided for above and where 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.

9. SPECIAL CASES T

a. Where Customer requests service that is seasonal, intermittent, speculative in nature, at voltages of 34.5kV or greater, or where the facilities requested by Customer do not meet the Terms and Conditions outlined in previous sections of LINE EXTENSION PLAN and the anticipated revenues do not justify Company's installing facilities required to meet Customer's needs, Company may request that Customer deposit with Company a refundable amount to justify Company's investment. T
b. Each year for ten (10) years, Company shall refund to Customer, an amount calculated by: T
   i. Adding the sum of Customer's annual base rate monthly electric demand billing for that year to the sum of the annual base rate monthly electric billing of the monthly electric demand billing for that year of any Customer(s), who connects directly to the facilities provided for in this agreement and requiring no further investment by Company T
   ii. times the refundable amount divided by the estimated total ten (10) year base rate electric demand billing required to justify the investment. T
c. 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. T

Terms and Conditions

Energy Curtailment and Service Restoration Procedures

PURPOSE

To provide procedures for reducing the consumption of electric energy on 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.

Terms and Conditions
Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

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.

Although, when practical, these types of uses will be given special consideration when implementing the manual load-shedding provisions of this program, any Customer may be affected by rotating or unplanned outages and should install emergency generation equipment if continuity of service is essential. Where the emergency is system-wide in nature, consideration will be given to the use of rotating outages as operationally practicable. In case of Customers supplied from two utility sources, only one source will be given special consideration. Also, any other Customers who, in their opinion, have critical equipment should install emergency generation equipment.

Company maintains lists of Customers with life support equipment and other critical needs for the purpose of curtailments and service restorations. Company, lacking knowledge of changes that may occur at any time in Customer's equipment, operation, and backup resources, does not assume the responsibility of identifying Customers with priority needs. It shall, therefore, be the Customer's responsibility to notify Company if Customer has critical needs.

II. Critical Commercial and Industrial Uses -- Except as described in Section III below, these uses shall include commercial or industrial operations requiring regimented shutdowns to prevent conditions hazardous to the general population, and to energy utilities and their support facilities critical to the production, transportation, and distribution of service to the general population. Company shall maintain a list of such Customers for the purpose of curtailments and service restoration.

III. Residential Use -- The priority of residential use during certain weather conditions (for example severe winter weather) will receive precedence over critical commercial and industrial uses. The availability of Company service personnel and the circumstances associated with the outage will also be considered in the restoration of service.

IV. Non-critical commercial and industrial uses.

V. Nonessential Uses -- The following and similar types of uses of electric energy shall be considered nonessential for all Customers:

Terms and Conditions
Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

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.

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.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After January 4, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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

Terms and Conditions
Energy Curtailment and Service Restoration Procedures

CURTAILMENT PROCEDURES (continued)

4. Company's use of electric energy in the operation of its offices and other facilities will be reduced to a minimum.

5. The Kentucky Public Service Commission will be advised of the situation.

6. An appeal will be made to Customers through the news media and/or personal contact to voluntarily curtail as much load as possible. The appeal will emphasize the defined priority levels as set forth above.

7. Customers will be advised through the use of the news media and personal contact that load interruption is imminent.

8. Implement procedures for interruption of selected distribution circuits.

SERVICE RESTORATION PROCEDURES

Where practical, priority uses will be considered in restoring service and service will be restored in the order I through IV as defined under PRIORITY LEVELS. However, because of the varieties of unpredictable circumstances which may exist or precipitate outages, it may be necessary to balance specific individual needs with infrastructure needs that affect a larger population. When practical, Company will attempt to provide estimates of repair times to aid Customers in assessing the need for alternative power sources and temporary relocations.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(4)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

New or revised tariff sheets, if applicable, identified in compliance with 807 KAR 5:011, shown either by providing: (a) The present and proposed tariffs in comparative form on the same sheet side by side or on facing sheets side by side; or (b) A copy of the present tariff indicating proposed additions by italicized inserts or underscoring and striking over proposed deletions.

Response:

See attached present and proposed tariffs in comparative form on the same sheet side-by-side. Please note that on each sheet of the side-by-side comparison the present tariff is on the left and the proposed tariff is on the right.

P.S.C. No. 18
Canceling P.S.C. No. 17

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

In all territory served as stated on Tariff Sheet No. 1.2 of this Book T

PUBLIC SERVICE COMMISSION

OF KENTUCKY

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

P.S.C. No. 19
Canceling P.S.C. No. 18

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky
www.lge-ku.com

Rates, Terms, and Conditions for Furnishing

ELECTRIC SERVICE

In all territory served as stated on Tariff Sheet No. 1.2 of this Book

PUBLIC SERVICE COMMISSION

OF KENTUCKY

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

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RTOD-Energy	Residential Time-of-Day Energy Service	6	
RTOD-Demand	Residential Time-of-Day Demand Service	7	
VFD	Volunteer Fire Department Service	9	
GS	General Service	10	
AES	All Electric School	12	
PS	Power Service	15	
TODS	Time-of-Day Secondary Service	20	
TODP	Time-of-Day Primary Service	22	
RTS	Retail Transmission Service	25	
FLS	Fluctuating Load Service	30	
LS	Lighting Service	35	
RLS	Restricted Lighting Service	36	
LE	Lighting Energy Service	37	
TE	Traffic Energy Service	38	
PSA	Pole and Structure Attachment Charges	40	T
EVSE	Electric Vehicle Supply Equipment	41	
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			D
SECTION 2 – Riders to Standard Rate Schedules			
CSR-1	Curtailable Service Rider-1	50	T
CSR-2	Curtailable Service Rider-2	51	N
SQF	Small Capacity Cogeneration Qualifying Facilities	55	
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NMS	Net Metering Service	57	
EF	Excess Facilities	60	
RC	Redundant Capacity	61	
IL	Intermittent Load	65	D/T
TS	Temporary/Seasonal Service	66	T
KWH	Kilowatt-Hours Consumed By Lighting Unit	67	

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 1

General Index
Rates, Terms, and Conditions T

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	Returned Payment Charge		
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CSR-2	Curtailable Service Rider-2	51	
SQF	Small Capacity Cogeneration Qualifying Facilities	55	
LQF	Large Capacity Cogeneration Qualifying Facilities	56	
NMS	Net Metering Service	57	
EF	Excess Facilities	60	
RC	Redundant Capacity	61	
IL	Intermittent Load	65	
TS	Temporary-to-Permanent and Seasonal Service	66	T
KWH	Kilowatt-Hours Consumed By Lighting Unit	67	

DATE OF ISSUE: September 28, 2018

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 1.1
Canceling P.S.C. No. 18, Original Sheet No. 1.1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 1.1

General Index
Rates, Terms, and Conditions T

DATE OF ISSUE: September 28, 2018

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 1.2 N

GENERAL INDEX
Territory Served

KU generates and purchases electricity, and distributes and sells electricity at retail in the following counties:

Adair	Edmonson	Jessamine	Ohio
Anderson	Estill	Knox	Oldham
Ballard	Fayette	Larue	Owen
Barren	Fleming	Laurel	Pendleton
Bath	Franklin	Lee	Pulaski
Bell	Fulton	Lincoln	Robertson
Bourbon	Gallatin	Livingston	Rockcastle
Boyle	Garrard	Lyon	Rowan
Bracken	Grant	Madison	Russell
Bullitt	Grayson	Marion	Scott
Caldwell	Green	Mason	Shelby
Campbell	Hardin	McCracken	Spencer
Carlisle	Harlan	McCreary	Taylor
Carroll	Harrison	McLean	Trimble
Casey	Hart	Mercer	Union
Christian	Henderson	Montgomery	Washington
Clark	Henry	Muhlenberg	Webster
Clay	Hickman	Nelson	Whitley
Crittenden	Hopkins	Nicholas	Woodford
Daviess			

All references hereinafter to “territory served” shall be determined by the Counties listed above.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 1.2

General Index
Territory Served

KU generates and purchases electricity, and distributes and sells electricity at retail in the following counties:

Adair	Edmonson	Jessamine	Ohio
Anderson	Estill	Knox	Oldham
Ballard	Fayette	Larue	Owen
Barren	Fleming	Laurel	Pendleton
Bath	Franklin	Lee	Pulaski
Bell	Fulton	Lincoln	Robertson
Bourbon	Gallatin	Livingston	Rockcastle
Boyle	Garrard	Lyon	Rowan
Bracken	Grant	Madison	Russell
Bullitt	Grayson	Marion	Scott
Caldwell	Green	Mason	Shelby
Campbell	Hardin	McCracken	Spencer
Carlisle	Harlan	McCreary	Taylor
Carroll	Harrison	McLean	Trimble
Casey	Hart	Mercer	Union
Christian	Henderson	Montgomery	Washington
Clark	Henry	Muhlenberg	Webster
Clay	Hickman	Nelson	Whitley
Crittenden	Hopkins	Nicholas	Woodford
Daviess			

All references hereinafter to “territory served” shall be determined by the Counties listed above.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Third Revision of Original Sheet No. 5
Canceling P.S.C. No. 18, Second Revision of Original Sheet No. 5

Standard Rate **RS**

RESIDENTIAL SERVICE

APPLICABLE
In all territory served.

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

RATE

Basic Service Charge per month:	$12.25
Plus an Energy Charge per kWh:	$ 0.09047

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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
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 sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% 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: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 5

Standard Rate **RS**

Residential Service

APPLICABLE
In all territory served.

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

RATE

Basic Service Charge per day:	$0.53			T/I
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	N
	$0.06318	$0.03234	$0.09552	N/I

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	D/T
Home Energy Assistance Program	Sheet No. 92	T
Franchise Fee	Sheet No. 90	T
School Tax	Sheet No. 91	T

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

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges. 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. T

Beginning May 1, 2019, Residential Service Customers in good standing by not having been assessed a Late Payment Charge for the previous eleven (11) months have the option of waiving one (1) late payment charge upon request. This option may only be used once every twelve (12) months as long as the Customer remains in good standing. N N N N

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Third Revision of Original Sheet No. 6
Canceling P.S.C. No. 18, Second Revision of Original Sheet No. 6

Standard Rate **RTOD-Energy**
Residential Time-of-Day Energy Service

APPLICABLE
In the territory served.

AVAILABILITY OF SERVICE
RTOD-Energy shall be available as an option to customers otherwise served under rate schedule RS.

1) Service under this rate schedule is limited to a maximum of five hundred (500) customers taking service on RTOD-Energy and RTOD-Demand combined that are eligible for Rate RS. Company will accept customers on a first-come-first-served basis.
2) This service is also available to customers on rate schedule 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) who demonstrate power delivered to such detached garage 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 electing to take service under this rate schedule who subsequently elects to take service under the standard Rate RS may not be allowed to return to this optional rate for 12 months from the date of exiting this rate schedule.

RATE

Basic Service Charge per month:	$12.25
Plus an Energy Charge per kWh:	
Off-Peak Hours:	$ 0.05892
On-Peak Hours:	$ 0.27615

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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
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: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 6

Standard Rate **RTOD-Energy**
Residential Time-of-Day Energy Service

APPLICABLE
In the territory served.

AVAILABILITY T
Available as an option to Customers otherwise served under Rate RS. T

1. Service under this rate schedule is limited to a maximum of five hundred (500) Customers taking service on Rates RTOD-Energy and RTOD-Demand combined that are eligible for Rate RS. Company will accept Customers on a first-come-first-served basis. T
2. This service is also available to Customers on Rate GS (where the Rate GS service is used in conjunction with a Rate RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month) who demonstrate power delivered to such detached garage is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include: T T
   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 electing to take service under this rate schedule who subsequently elects to take service under Rate RS may not be allowed to return to this optional rate for twelve (12) months from the date of exiting this rate schedule. T

RATE

Basic Service Charge per day:	$0.53			T/I
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	N
Off-Peak Hours:	$0.02658	$0.03234	$0.05892	N
On-Peak Hours:	$0.28583	$0.03234	$0.31817	N/I

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	D/T
Home Energy Assistance Program	Sheet No. 92	T
Franchise Fee	Sheet No. 90	T
School Tax	Sheet No. 91	T

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 6.1

Standard Rate **RTOD-Energy**
Residential Time-of-Day Energy 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 April through October

	Off-Peak	On-Peak
Weekdays	5 PM – 1 PM	1 PM - 5 PM
Weekends	All Hours	

All Other Months of November continuously through March

	Off-Peak	On-Peak	
			T
Weekdays	11 AM - 7 AM	7 AM – 11 AM	
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 sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% 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. Customers served under this optional residential rate 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: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 6.1

Standard Rate **RTOD-Energy**
Residential Time-of-Day Energy Service

RATING PERIODS T
The rating periods are established in Eastern Standard Time year-round by season for weekdays T
and weekends throughout Company's service territory, and shall be as follows: T

Summer Months of April through October

	Off-Peak	On-Peak
Weekdays	5 PM - 1 PM	1 PM - 5 PM
Weekends	All Hours	

All Other Months of November continuously through March

	Off-Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM - 11 AM
Weekends	All Hours	

If a legal holiday falls on a weekday, it will be considered a weekday. N

MINIMUM CHARGE
The Basic Service Charge shall be the Minimum Charge.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

Beginning May 1, 2019, RTOD-Energy Customers in good standing by not having been assessed N
a Late Payment Charge for the previous eleven (11) months have the option of waiving one (1) N
late payment charge upon request. This option may only be used once every twelve (12) months N
as long as the Customer remains in good standing. N

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional residential rate 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: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Third Revision of Original Sheet No. 7
Canceling P.S.C. No. 18, Second Revision of Original Sheet No. 7

Standard Rate **RTOD-Demand**

Residential Time-of-Day Demand Service

APPLICABLE

In the territory served.

AVAILABILITY OF SERVICE

RTOD-Demand shall be available as an option to customers otherwise served under rate schedule RS.

1) Service under this rate schedule is limited to a maximum of five hundred (500) customers taking service on RTOD-Demand and RTOD-Energy combined that are eligible for Rate RS. Company will accept customers on a first-come-first-served basis.
2) This service is also available to customers on rate schedule 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) who demonstrate power delivered to such detached garage 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 electing to take service under this rate schedule who subsequently elects to take service under the standard Rate RS may not be allowed to return to this optional rate for 12 months from the date of exiting this rate schedule.

RATE

Basic Service Charge per month:	$12.25
Plus an Energy Charge per kWh:	$ 0.04478
Plus a Demand Charge per kW:	
Base Hours:	$ 3.44
Peak Hours:	$ 7.87

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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand Side Management Cost Recovery Mechanism	Sheet No. 86	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
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: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 7

Standard Rate **RTOD-Demand**

Residential Time-of-Day Demand Service

APPLICABLE

In the territory served.

AVAILABILITY T

Available as an option to Customers otherwise served under Rate RS. T

1. Service under this rate schedule is limited to a maximum of five-hundred (500) Customers taking service on Rates RTOD-Demand and RTOD-Energy combined that are eligible for Rate RS. Company will accept Customers on a first-come-first-served basis. T
2. This service is also available to Customers on Standard Rate GS (where the Rate GS service is used in conjunction with a Rate RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month) who demonstrate power delivered to such detached garage is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include: T T
   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 electing to take service under this rate schedule who subsequently elects to take service under Rate RS may not be allowed to return to this optional rate for twelve (12) months from the date of exiting this rate schedule. T

RATE

Basic Service Charge per day:	$0.53			T/I
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	N
	$0.01244	$0.03234	$0.04478	N
Plus a Demand Charge per kW:				
Base Hours:	$3.44			
Peak Hours:	$8.90			I

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	D/T
Home Energy Assistance Program	Sheet No. 92	T
Franchise Fee	Sheet No. 90	T
School Tax	Sheet No. 91	T

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 7.1

Standard Rate **RTOD-Demand**
Residential Time-of-Day Demand 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 April through October

	Base	Peak	
			T
Weekdays	All Hours	1 PM - 5 PM	T
Weekends	All Hours		

All Other Months of November continuously through March

	Base	Peak	
			T
Weekdays	All Hours	7 AM – 11 AM	T
Weekends	All Hours		

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

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.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% 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. Customers served under this optional residential rate 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: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 7.1

Standard Rate **RTOD-Demand**
Residential Time-of-Day Demand Service

RATING PERIODS T
The rating periods are established in Eastern Standard Time year-round by season for weekdays T
and weekends throughout Company's service territory, and shall be as follows: T

Summer Months of April through October

	Base	Peak
Weekdays	All Hours	1 PM - 5 PM
Weekends	All Hours	

All Other Months of November continuously through March

	Base	Peak
Weekdays	All Hours	7 AM - 11 AM
Weekends	All Hours	

If a legal holiday falls on a weekday, it will be considered a weekday. N

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

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.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

Beginning May 1, 2019, RTOD-Demand Customers in good standing by not having been N
assessed a Late Payment Charge for the previous eleven (11) months have the option of waiving N
one (1) late payment charge upon request. This option may only be used once every twelve (12) N
months as long as the Customer remains in good standing. N

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional residential rate 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: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Third Revision of Original Sheet No. 9
Canceling P.S.C. No. 18, Second Revision of Original Sheet No. 9

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 per month:	$12.25
Plus an Energy Charge per kWh:	$ 0.09047

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

Fuel Adjustment Clause	Sheet No. 85	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
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 sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% 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 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 9

Standard Rate **VFD**

Volunteer Fire Department Service

APPLICABLE
In all territory served.

AVAILABILITY T
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 Customer with Customer determining whether service will be provided under T
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 per day:	$0.53			T/I
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	N
	$0.06318	$0.03234	$0.09552	N/I

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

Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	D/T
Franchise Fee	Sheet No. 90	T
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 sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 3% 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: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Third Revision of Original Sheet No. 10
Canceling P.S.C. No. 18, Second 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 customers whose 12-month-average monthly maximum loads do not exceed 50 kW. Existing customers with 12-month-average maximum monthly loads exceeding 50 kW who are receiving service under P.S.C. 13, Fourth Revision of Original Sheet No. 10 as of February 6, 2009, will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer.

RATE

Basic Service Charge per month:	$31.50 single-phase service
	$50.40 three-phase service
Plus an Energy Charge per kWh:	$0.10490

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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee Rider	Sheet No. 90	
School Tax	Sheet No. 91	

DETERMINATION OF LOAD

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.

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 10

Standard Rate **GS**

General Service

APPLICABLE

In all territory served.

AVAILABILITY T

To general lighting and small power loads for secondary service.

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

RATE

Basic Service Charge per day:	$1.04 single-phase service			T/I
	$1.66 three-phase service			T/I
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	N
	$0.08108	$0.03271	$0.11379	N/I

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	D/T
Franchise Fee	Sheet No. 90	T
School Tax	Sheet No. 91	

DETERMINATION OF LOAD

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.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 10.1

Standard Rate **GS**

GENERAL SERVICE RATE

DETERMINATION OF MAXIMUM LOAD T

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

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% 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: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00370 dated June 22, 2017 and modified June 29, 2017**

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 10.1

Standard Rate **GS**

General Service

DETERMINATION OF MAXIMUM LOAD

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 Customer during the 15-minute period of maximum use during the month. T

MINIMUM CHARGE

The Basic Service Charge shall be the Minimum Charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% 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: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00294 dated ____**

Kentucky Utilities Company

P.S.C. No. 18, Second Revision of Original Sheet No. 12
Canceling P.S.C. No. 18, First Revision of Original Sheet No. 12

Standard Rate **AES**

ALL ELECTRIC SCHOOL

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

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

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

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

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

RATE

Basic Service Charge per meter per month:	$ 85.00 single-phase service $140.00 three-phase service	
Plus an Energy Charge per kWh:	$ 0.08244	I

DATE OF ISSUE: January 8, 2018

DATE EFFECTIVE: January 30, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2017-00266 dated December 19, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 12

Standard Rate **AES**

All Electric School

APPLICABLE

In all territory served.

AVAILABILITY T

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

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

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

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

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

RATE

Basic Service Charge per day:	$ 2.80 single-phase service			T/I
	$ 4.60 three-phase service			T/I
Plus an Energy Charge per kWh:	Infrastructure	Variable	Total	N
	$0.05637	$0.03251	$0.08888	N/I

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 12.1
Canceling P.S.C. No. 18, Original Sheet No. 12.1

Standard Rate **AES**
ALL ELECTRIC SCHOOL

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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
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 sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 12.1

Standard Rate **AES**
All Electric School

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D/T
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 sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Second Revision of Original Sheet No. 15
Canceling P.S.C. No. 18, First Revision of Original Sheet No. 15

Standard Rate **PS**

POWER SERVICE

APPLICABLE
In all territory served.

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

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

RATE

	Secondary	Primary	
Basic Service Charge per month:	$90.00	$240.00	
Plus an Energy Charge per kWh:	$ 0.03270	$ 0.03171	
Plus a Demand Charge per kW:			
Summer Rate:			
(Five Billing Periods of May through September)	$21.03	$ 21.21	I
Winter Rate:			
(All other months)	$18.81	$ 19.02	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 measured load in the preceding eleven (11) monthly billing periods, or
c) if applicable, a minimum of 60% of the contract capacity based on the maximum expected load on the system or on facilities specified by Customer.

DATE OF ISSUE: January 8, 2018

DATE EFFECTIVE: January 30, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2017-00266 dated December 19, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 15

Standard Rate **PS**

Power Service

APPLICABLE
In all territory served.

AVAILABILITY T

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

RATE

	Secondary	Primary	
Basic Service Charge per day:	$2.96	$7.89	T/I
Plus an Energy Charge per kWh:	$0.03270	$0.03209	I
Plus a Demand Charge per kW:			
Summer Rate:			
(Five Billing Periods of May through September)	$23.22	$23.32	I
Winter Rate:			
(All other months)	$20.78	$20.91	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 measured load in the preceding eleven (11) monthly billing periods, or
c. if applicable, a minimum of 60% of the contract capacity based on the maximum expected load on the system or on facilities specified by Customer.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 15.1
Canceling P.S.C. No. 18, Original Sheet No. 15.1

Standard Rate **PS**
POWER 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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
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 month.

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

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

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

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

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

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

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 15.1

Standard Rate **PS**
Power 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	T
......	Fuel Adjustment Clause	Sheet No. 85	T
	Off-System Sales Adjustment Clause	Sheet No. 88	T
	Environmental Cost Recovery Surcharge	Sheet No. 87	D/T
	Franchise Fee	Sheet No. 90	T
	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 month.

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

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than ninety (90) percent in accordance with the following formula: (based on power factor measured at the time of maximum load). T

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

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

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

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Third Revision of Original Sheet No. 20
Canceling P.S.C. No. 18, Second Revision of Original Sheet No. 20

Standard Rate **TODS**

TIME-OF-DAY SECONDARY SERVICE

APPLICABLE
In all territory served.

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

RATE

Basic Service Charge per month:	$200.00
Plus an Energy Charge per kWh:	$ 0.03229
Plus a Maximum Load Charge per kW:	
Peak Demand Period:	$ 8.09
Intermediate Demand Period:	$ 6.41
Base Demand Period:	$ 3.03

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 measured load 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) the highest measured load in the preceding eleven (11) monthly billing periods, or
c) 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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
Franchise Fee Rider	Sheet No. 90	
School Tax	Sheet No. 91	

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 20

Standard Rate **TODS**

Time-of-Day Secondary Service

APPLICABLE
In all territory served.

AVAILABILITY T
Available for secondary service to Customers whose twelve (12) month-average monthly minimum loads exceed 250 kVA, and whose twelve (12) month-average monthly maximum loads do not exceed 5,000 kVA. T T T

RATE

Basic Service Charge per day:	$6.58	T/I
Plus an Energy Charge per kWh:	$0.03248	I
Plus a Maximum Load Charge per kVA:		T
Peak Demand Period:	$8.17	I
Intermediate Demand Period:	$6.47	I
Base Demand Period:	$2.65	R

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

the monthly billing demand for the Base Demand Period is the greater of:
1. the maximum measured load in the current billing period but not less than 250 kVA, or T
2. the highest measured load in the preceding eleven (11) monthly billing periods, or T
3. the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. T

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D/T
School Tax	Sheet No. 91	

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 20.1

Standard Rate **TODS**
TIME-OF-DAY SECONDARY 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 appropriate rating period each month. Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed based on the measured kVA times 90 percent, at the applicable kW charge.

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

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

RATING PERIODS

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

Summer peak months of May through September

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

All other months of October continuously through April

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

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 20.1

Standard Rate **TODS**
Time-of-Day Secondary Service

DETERMINATION OF MAXIMUM LOAD

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

D
D

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		

If a legal holiday falls on a weekday, it will be considered a weekday. N

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 20.2

Standard Rate **TODS**

TIME-OF-DAY SECONDARY SERVICE

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: July 7, 2017

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 20.2

Standard Rate **TODS**

Time-of-Day Secondary Service

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Third Revision of Original Sheet No. 22
Canceling P.S.C. No. 18, Second Revision of Original Sheet No. 22

Standard Rate **TODP**

TIME-OF-DAY PRIMARY SERVICE

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for primary service to any customer: (1) who has a 12-month-average monthly minimum demand exceeding 250 kVA; and (2) whose new or additional load receives any required approval of Company's transmission operator.

RATE

Basic Service Charge per month:	$330.00
Plus an Energy Charge per kWh:	$ 0.03136
Plus a Maximum Load Charge per kVA:	
Peak Demand Period:	$ 6.71
Intermediate Demand Period:	$ 5.31
Base Demand Period:	$ 3.03

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 measured load 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) the highest measured load in the preceding eleven (11) monthly billing periods, or
c) 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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
Franchise Fee Rider	Sheet No. 90	
School Tax	Sheet No. 91	

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 22

Standard Rate **TODP**

Time-of-Day Primary Service

APPLICABLE
In all territory served.

AVAILABILITY T
Available for primary service to Customers whose twelve (12) month-average monthly minimum demands exceed 250 kVA, and whose new or additional load receives any required approval of Company's transmission operator. T T

RATE

Basic Service Charge per day:	$10.84	T/R
Plus an Energy Charge per kWh:	$0.03161	I
Plus a Maximum Load Charge per kVA:		
Peak Demand Period:	$7.79	I
Intermediate Demand Period:	$6.16	I
Base Demand Period:	$2.87	R

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

the monthly billing demand for the Base Demand Period is the greater of:
1. the maximum measured load in the current billing period but not less than 250 kVA, or T
2. the highest measured load in the preceding eleven (11) monthly billing periods, or T
3. the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. T

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D/T
School Tax	Sheet No. 91	

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 22.1

Standard Rate **TODP**

TIME-OF-DAY PRIMARY SERVICE

DETERMINATION OF MAXIMUM LOAD T

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.

Customers who own and operate onsite generation of 1 MW or larger that is not for emergency backup will be provided a 60-minute exemption from measuring load for billing purposes following a Company-system fault, but not a Company energy spike, a fault on a customer's system, or other causes or events that result in the customer's generation coming offline. The 60-minute exemption will begin after Company's SCADA system indicates service has been restored. N

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 sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE T

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 22.1

Standard Rate **TODP**

Time-of-Day Primary Service

DETERMINATION OF MAXIMUM LOAD

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

Customers who own and operate onsite generation of one (1) MW or larger that is not for emergency backup will be provided a 60-minute exemption from measuring load for billing purposes following a Company-system fault, but not a Company energy spike, a fault on a Customer's system, or other causes or events that result in the Customer's generation coming offline. The 60-minute exemption will begin after Company's SCADA system indicates service has been restored. T

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		

If a legal holiday falls on a weekday, it will be considered a weekday. N

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Third Revision of Original Sheet No. 25
Canceling P.S.C. No. 18, Second 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 to any customer: (1) who has a 12-month-average monthly minimum demand exceeding 250 kVA; and (2) whose new or additional load receives any required approval of Company's transmission operator.

RATE

Basic Service Charge per month:	$1,500.00
Plus an Energy Charge per kWh:	$ 0.03058
Plus a Maximum Load Charge per kVA:	
Peak Demand Period:	$ 6.55
Intermediate Demand Period:	$ 5.18
Base Demand Period:	$ 2.23

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 measured load 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) the highest measured load in the preceding eleven (11) monthly billing periods, or
c) 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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
Franchise Fee Rider	Sheet No. 90	
School Tax	Sheet No. 91	

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 25

Standard Rate **RTS**

Retail Transmission Service

APPLICABLE
In all territory served.

AVAILABILITY T
Available for transmission service to any Customer: (1) who has a twelve (12) month-average monthly minimum demand exceeding 250 kVA; and (2) whose new or additional load receives any required approval of Company's transmission operator. T

RATE

Basic Service Charge per day:	$49.28	T/R
Plus an Energy Charge per kWh:	$0.03101	I
Plus a Maximum Load Charge per kVA:		
Peak Demand Period:	$7.59	I
Intermediate Demand Period:	$6.01	I
Base Demand Period:	$1.97	R

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

the monthly billing demand for the Base Demand Period is the greater of:
1. the maximum measured load in the current billing period but not less than 250 kVA, or T
2. the highest measured load in the preceding eleven (11) monthly billing periods, or T
3. the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. T

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D/T
School Tax	Sheet No. 91	

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, 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 sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 19, 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		

If a legal holiday falls on a weekday, it will be considered a weekday. N

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Second Revision of Original Sheet No. 30
Canceling P.S.C. No. 18, First Revision of Original Sheet No. 30

Standard Rate **FLS**

Fluctuating Load Service

APPLICABLE
In all territory served.

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

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

BASE RATE

	Primary	Transmission	
Basic Service Charge per month:	$330.00	$1,500.00	
Plus an Energy Charge per kWh:	$ 0.03136	$ 0.03036	
Plus a Maximum Load Charge per kVA:			
Peak Demand Period:	$ 6.03	$ 3.37	I
Intermediate Demand Period:	$ 4.60	$ 2.41	I
Base Demand Period:	$ 2.57	$ 1.65	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 measured load 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) the highest measured load in the preceding eleven (11) monthly billing periods, or
c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

DATE OF ISSUE: January 8, 2018

DATE EFFECTIVE: January 30, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2017-00266 dated December 19, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 30

Standard Rate **FLS**

Fluctuating Load Service

APPLICABLE
In all territory served.

AVAILABILITY T
Available for primary or transmission service to Customers up to an aggregate of two hundred (200) MVA for all Customers taking service under this schedule and under the Fluctuating Load Service Rate FLS schedule of Louisville Gas and Electric Company. This schedule is restricted to individual Customers whose monthly demand is twenty (20) MVA or greater. A Customer is defined as a fluctuating load if that Customer's load either increases or decreases twenty (20) MVA or more per minute or seventy (70) MVA or more in ten (10) minutes when such increases or decreases exceed one (1) occurrence per hour during any hour of the billing month.

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

BASE RATE

	Primary	Transmission	
Basic Service Charge per day:	$10.84	$49.28	T/R/R
Plus an Energy Charge per kWh:	$0.03161	$0.03101	I/I
Plus a Maximum Load Charge per kVA:			
Peak Demand Period:	$7.40	$3.88	I/I
Intermediate Demand Period:	$5.80	$2.76	I/I
Base Demand Period:	$2.68	$1.65	I

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

the monthly billing demand for the Base Demand Period is the greater of:
1. the maximum measured load in the current billing period but not less than 20,000 kVA, or T
2. the highest measured load in the preceding eleven (11) monthly billing periods, or T
3. the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. T

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 30.1
Canceling P.S.C. No. 18, Original Sheet No. 30.1

Standard Rate **FLS**
Fluctuating Load 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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
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 sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, 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: T

Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	
Fuel Adjustment Clause	Sheet No. 85	
Off-System Sales Adjustment Clause	Sheet No. 88	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D/T
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		

If a legal holiday falls on a weekday, it will be considered a weekday. N

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE
If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, 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 years with successive one year term renewal until canceled by either party giving at least one (1) year written notice to the other prior to the end of the initial term or the then current annual renewal period, as applicable.

PROTECTION OF SERVICE

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other undesirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 15(1)(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. 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 either Rider CSR-1 or CSR-2. Company's right to interrupt under this provision is T

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, 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 T 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 Customer exceed the limits set forth in the IEEE standards for such T characteristics. In addition, if Customer's use of Company's service under this schedule causes T 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 Customer in accordance with 807 KAR 5:006, Section 15(1)(b). T 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 Customer's expense. T

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 either Rider CSR-1 or CSR-2. Company's right to interrupt under this provision is

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 30.3

Standard Rate **FLS**
Fluctuating Load Service

restricted to responses to unplanned outage or de-rates of LG&E and KU Energy LLC System (LKE System) owned or purchased generation or when Automatic Reserve Sharing is invoked. LKE System, as used herein, shall consist of KU and LG&E. At customer's request, Company shall provide documentation of the need for interruption under this provision within sixty (60) days of the end of the applicable billing period.

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: July 7, 2017

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 30.3

Standard Rate **FLS**
Fluctuating Load Service

restricted to responses to unplanned outage or de-rates of LG&E and KU Energy LLC System (LKE System) owned or purchased generation or when Automatic Reserve Sharing is invoked. LKE System, as used herein, shall consist of KU and LG&E. At Customer's request, Company shall provide documentation of the need for interruption under this provision within sixty (60) days of the end of the applicable billing period.

LIABILITY
In no event shall Company have any liability to Customer or any other party affected by the electrical T
service to Customer for any consequential, indirect, incidental, special, or punitive damages, and T
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 T
Company's service causes damage to Company's property or injuries to persons, Customer shall be T
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: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Second Revision of Original Sheet No. 35
Canceling P.S.C. No. 18, First Revision of 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.

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	Monthly Charge Ornamental	
High Pressure Sodium						
462/472	Cobra Head	5,800	0.083	$ 10.10	$13.77	I
463/473	Cobra Head	9,500	0.117	10.49	14.36	
464/474	Cobra Head	22,000*	0.242	16.28	20.43	
465/475	Cobra Head	50,000*	0.471	25.75	28.53	
487	Directional	9,500	0.117	$10.33		
488	Directional	22,000*	0.242	15.62		
489	Directional	50,000*	0.471	22.09		
428	Open Bottom	9,500	0.117	$ 9.01		
Metal Halide						
451	Directional	32,000*	0.350	$23.07		
Light Emitting Diode (LED)						
390	Cobra Head	8,179	0.080	$15.88		
391	Cobra Head	14,166*	0.134	18.60		
392	Cobra Head	23,214*	0.228	27.95		

DATE OF ISSUE: January 8, 2018

DATE EFFECTIVE: January 30, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2017-00266 dated December 19, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 35

Standard Rate **LS**

Lighting Service

APPLICABLE
In all territory served.

AVAILABILITY T
Available under the conditions set out hereinafter for lighting applications such as, but not limited to, the illumination of streets, 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.

D

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).

D

RATE

Rate Code	Type of Fixture	Lumen Range	kW Per Light	Monthly Charge Fixture Only	
					T T D
Light Emitting Diode (LED)					
390	Cobra Head	6,000-8,200	0.071	$10.23	T/R
391	Cobra Head	13,000-16,500	0.122	$12.34	T/R
392	Cobra Head	22,000-29,000	0.194	$15.67	T/R
393	Open Bottom	4,500-6,000	0.048	$ 8.80	T/R
KC1	Cobra Head	2,500-4,000	0.022	$ 8.95	N
KF1	Directional (Flood)	4,500-6,000	0.030	$11.65	N
KF2	Directional (Flood)	14,000-17,500	0.096	$13.51	N
KF3	Directional (Flood)	22,000-28,000	0.175	$15.96	N
KF4	Directional (Flood)	35,000-50,000	0.297	$22.87	N

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Second Revision of Original Sheet No. 35.1
Canceling P.S.C. No. 18, First Revision of Original Sheet No. 35.1

Standard Rate **LS**
Lighting Service

OVERHEAD SERVICE (continued)
RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	
LED (continued)					
393	Open Bottom	5,007	0.050	$10.71	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.

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

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

RATE

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							I
467	Colonial	5,800	0.083		$12.84		
468	Colonial	9,500	0.117		13.07		
401/411	Acorn	5,800	0.083		$17.43	$24.76	
420/430	Acorn	9,500	0.117		17.79	25.25	
414	Victorian	5,800	0.083			$34.32	
415	Victorian	9,500	0.117			34.53	
492/476	Contemporary	5,800	0.083	$17.36	$19.60		
497/477	Contemporary	9,500	0.117	17.14	24.09		
498/478	Contemporary	22,000*	0.242	20.04	31.05		
499/479	Contemporary	50,000*	0.471	24.29	38.26		
300	Dark Sky	4,000	0.060		$25.05		
301	Dark Sky	9,500	0.117		26.13		

DATE OF ISSUE: January 8, 2018

DATE EFFECTIVE: January 30, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2017-00266 dated December 19, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 35.1

Standard Rate **LS**
Lighting Service

UNDERGROUND SERVICE T/D
Based on Customer's lighting choice, Company will furnish, own, install, and maintain poles, fixtures, and any necessary circuitry up to 200 feet. All poles and fixtures furnished by Company will be standard stocked materials. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for underground installation.

RATE D

Rate Code	Type of Fixture	Lumen Range	kW Per Light	Fixture Charge	N
Light Emitting Diode (LED)					
KC2	Cobra Head	2,500-4,000	0.022	$ 4.13	N
396	Cobra Head	6,000-8,200	0.071	$ 5.40	T/R
397	Cobra Head	13,000-16,500	0.122	$ 7.52	T/R
398	Cobra Head	22,000-29,000	0.194	$10.85	T/R
399	Colonial, 4-Sided	4,000-7,000	0.044	$ 7.65	T/R
KA1	Acorn	4,000-7,000	0.040	$ 9.12	N
KN1	Contemporary	4,000-7,000	0.057	$ 7.09	N
KN2	Contemporary	8,000-11,000	0.087	$ 8.25	N
KN3	Contemporary	13,500-16,500	0.143	$10.03	N
KN4	Contemporary	21,000-28,000	0.220	$14.55	N
KN5	Contemporary	45,000-50,000	0.380	$21.95	N
KF5	Directional (Flood)	4,500-6,000	0.030	$ 8.45	N
KF6	Directional (Flood)	14,000-17,500	0.096	$10.31	N
KF7	Directional (Flood)	22,000-28,000	0.175	$12.75	N
KF8	Directional (Flood)	35,000-50,000	0.297	$19.67	N

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Standard Rate **LS**
Lighting Service

UNDERGROUND SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth
Metal Halide					
491/495	Contemporary	32,000*	0.350	$24.95	$39.14
Light Emitting Diode (LED)					
396	Cobra Head	8,179	0.080		$36.40
397	Cobra Head	14,166*	0.134		39.12
398	Cobra Head	23,214*	0.228		48.46
399	Colonial, 4-Sided	5,665	0.068		$38.22

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

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

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) 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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
Franchise Fee Rider	Sheet No. 90	
School Tax	Sheet No. 91	

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00034 dated March 20, 2018 and modified March 28, 2018

Standard Rate **LS**
Lighting Service

RATE (continued) T

Rate Code	Type of Fixture	Lumen Range	kW Per Light	Monthly Charge	
					T T
High Pressure Sodium					
414	Victorian*	5,800	0.083	$36.75	I
415	Victorian*	9,500	0.117	$36.98	I

Colonial and Acorn "Post Top" lights must include one of two pole options, a Decorative Smooth pole or a Historic Fluted pole. Underground fed Cobra and Contemporary LEDs must include a Cobra pole charge or Contemporary pole charge, respectively. The Underground fed Directional (Flood) LEDs must include a Cobra or Contemporary pole charge. N

Pole Charges

Rate Code	Pole Type	Monthly Pole Charge
PK1	Cobra	$12.49
PK2	Contemporary	$12.00
PK3	Post Top – Decorative Smooth	$ 8.25
PK4	Post Top – Historic Fluted	$15.48

CONVERSION FEE

Customer will be required to pay a monthly conversion fee for 60 months if Customer requests to change current functioning non-LED fixture to an LED fixture. This conversion fee represents the remaining book value of the current working non-LED fixture.

Conversion Fee: $6.12 per month for 60 months

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 35.3

Standard Rate **LS**
Lighting Service

T

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

TERMS AND CONDITIONS
1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.
2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults. Company shall initiate service corrections within two (2) business days after such notification by Customer.
3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.
4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.
5. If any permit is required from any municipal or other governmental authority with respect to installation and use of any of the lighting units provided hereunder, Company will seek such permits, but the ultimate responsibility belongs with Customer.
6. If Customer requests the removal of an existing lighting system, including, but not limited to, fixtures, poles, or other supporting facilities that were in service less than twenty years, and requests installation of replacement lighting within 5 years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.
7. Temporary suspension of lighting service is not permitted. Upon permanent discontinuance of service, lighting units and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 35.3

Standard Rate **LS**
Lighting Service

DUE DATE OF BILL T
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) 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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	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 (5) 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. T

TERMS AND CONDITIONS
1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.
2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults. Company shall initiate service corrections within two (2) business days after such notification by Customer.
3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.
4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.
5. If any permit is required from any municipal or other governmental authority with respect to installation and use of any of the lighting units provided hereunder, Company will seek such permits, but the ultimate responsibility belongs with Customer. T

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

KU Lighting Service Rate (LS) is now contained on five pages instead of four

Kentucky Utilities Company

T

TERMS AND CONDITIONS (continued)

6. If Customer requests the removal of an existing lighting system, including, but not limited to, fixtures, poles, or other supporting facilities, Customer agrees to pay to Company its cost of labor to remove existing facilities. Customer will be required to pay Conversion Fee if Customer requests installation of LED replacement within five (5) years.

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

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Second Revision of Original Sheet No. 36
Canceling P.S.C. No. 18, First Revision of Original Sheet No. 36

Standard Rate **RLS**

Restricted Lighting Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Service under this rate schedule is restricted to those lighting fixtures/poles in service as of January 1, 2013, except where a spot replacement maintains the continuity of multiple fixtures/poles comprising a neighborhood lighting system or continuity is desired for a subdivision being developed in phases. 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. Spot replacements will not be available for Mercury Vapor and Incandescent rate codes.

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.

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

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Fixture Only	Monthly Charge: Fixture and Pole	
High Pressure Sodium						
461/471	Cobra Head	4,000	0.060	$ 9.03	$12.35	I
409	Cobra Head	50,000	0.471	14.21		
426	Open Bottom	5,800	0.083	8.78		
Metal Halide						
450/454	Directional	12,000*	0.150	$16.47	$21.23	
455	Directional	32,000*	0.350		27.83	
452/459	Directional	107,800*	1.080	48.09	52.84	
Mercury Vapor						
446/456	Cobra Head	7,000	0.207	$10.93	$13.43	
447/457	Cobra Head	10,000	0.294	12.90	15.12	
448/458	Cobra Head	20,000	0.453	14.56	17.04	
404	Open Bottom	7,000	0.207	11.96		

DATE OF ISSUE: January 8, 2018

DATE EFFECTIVE: January 30, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2017-00266 dated December 19, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 36

Standard Rate **RLS**

Restricted Lighting Service

APPLICABLE
In all territory served.

AVAILABILITY T
Availability is restricted to those lighting fixtures/poles in service as of January 1, 2013, except T
where a spot replacement maintains the continuity of multiple fixtures/poles in a neighborhood T
lighting system or continuity is desired for a subdivision being developed in phases. 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. Spot replacements will not be available for Mercury Vapor and Incandescent rate codes.

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.

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 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). D

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge: Fixture Only	Monthly Charge: Fixture and Pole	
High Pressure Sodium						
461/471	Cobra Head	4,000	0.060	$ 9.67	$ 13.23	T/I/I
462/472	Cobra Head	5,800	0.083	10.82	14.75	N/I/I
463/473	Cobra Head	9,500	0.117	11.23	15.38	N/I/I
464/474	Cobra Head	22,000*	0.242	17.43	21.88	N/I/I
465/475	Cobra Head	50,000*	0.471	27.58	30.55	N/I/I
409	Cobra Head	50,000	0.471	15.22		T/I
426	Open Bottom	5,800	0.083	9.40		T/I
428	Open Bottom	9,500	0.117	9.65		N/I
487	Directional (Flood)	9,500	0.117	11.06		N/I
488	Directional (Flood)	22,000*	0.242	16.73		N/I
489	Directional (Flood)	50,000*	0.471	23.66		N/I

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Second Revision of Original Sheet No. 36.1
Canceling P.S.C. No. 18, First Revision of Original Sheet No. 36.1

Standard Rate **RLS**
Restricted Lighting Service

OVERHEAD SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	
Incandescent					I
421	Tear Drop	1,000	0.102	$ 3.81	
422	Tear Drop	2,500	0.201	5.05	
424	Tear Drop	4,000	0.327	7.51	
425	Tear Drop	6,000	0.447	10.02	

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

UNDERGROUND SERVICE

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

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth	Monthly Charge Historic Fluted	
Metal Halide							
460	Directional	12,000	0.150		$31.57		I
469	Directional	32,000	0.350		37.27		
470	Directional	107,800*	1.080		62.05		
490/494	Contemporary	12,000*	0.150	$17.79	$31.76		
493/496	Contemporary	107,800*	1.080	51.71	65.67		
High Pressure Sodium							
440/410	Acorn	4,000	0.060		$15.88	$23.33	
466	Colonial	4,000	0.060		$11.37		
412	Coach	5,800	0.083		$34.31		
413	Coach	9,500	0.117		34.54		

DATE OF ISSUE: January 8, 2018

DATE EFFECTIVE: January 30, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2017-00266 dated December 19, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 36.1

Standard Rate **RLS**
Restricted Lighting Service

OVERHEAD SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Fixture and Pole	T T
Metal Halide						N
450/454	Directional (Flood)	12,000*	0.150	$17.64	$22.74	N/I/I
455	Directional (Flood)	32,000*	0.350		29.80	N/I/I
452/459	Directional (Flood)	107,800*	1.080	51.50	56.59	N/I/I
451	Directional (Flood)	32,000*	0.350	24.71		N/I
Mercury Vapor						N
446/456	Cobra Head	7,000	0.207	$11.71	$14.38	N/I/I
447/457	Cobra Head	10,000	0.294	13.82	16.19	N/I/I
448/458	Cobra Head	20,000	0.453	15.59	18.25	N/I/I
404	Open Bottom	7,000	0.207	12.81		N/I
Incandescent						
421	Tear Drop	1,000	0.102	$ 4.09		I
422	Tear Drop	2,500	0.201	5.41		I
424	Tear Drop	4,000	0.327	8.03		I
425	Tear Drop	6,000	0.447	10.74		I

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

UNDERGROUND SERVICE

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

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Pole Type	Monthly Charge	T T
Metal Halide						
460	Directional (Flood)	12,000	0.150	Decorative Smooth	$33.81	T/I
469	Directional (Flood)	32,000	0.350	Decorative Smooth	39.91	T/I
470	Directional (Flood)	107,800*	1.080	Decorative Smooth	66.45	T/I

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

Standard Rate **RLS**
Restricted Lighting Service

UNDERGROUND SERVICE (continued)
RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Decorative Smooth
360	Granville	16,000	0.181	$63.76

Granville units are restricted to installations for the City of London.

DUE DATE OF BILL
Payment is due within sixteen (16) business days (no less than twenty-two (22) 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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
Franchise Fee Rider	Sheet No. 90	
School Tax	Sheet No. 91	

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

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

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

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

Standard Rate **RLS**
Restricted Lighting Service

UNDERGROUND SERVICE (continued)
RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Pole Type	Monthly Charge	T T
Metal Halide (continued)						
490	Contemporary	12,000*	0.150	Fixture Only	$19.05	I
491	Contemporary	32,000*	0.350	Fixture Only	$26.72	N/I
493	Contemporary	107,800*	1.080	Fixture Only	$55.38	I
494	Contemporary	12,000*	0.150	Decorative Smooth	$34.01	I
495	Contemporary	32,000*	0.350	Contemporary	$41.92	N/I
496	Contemporary	107,800*	1.080	Decorative Smooth	$70.33	I
High Pressure Sodium						
440	Acorn	4,000	0.060	Decorative Smooth	$17.02	I
410	Acorn	4,000	0.060	Historic Fluted	$24.98	I
401	Acorn	5,800	0.083	Decorative Smooth	$18.67	N/I
411	Acorn	5,800	0.117	Historic Fluted	$26.52	N/I
420	Acorn	9,500	0.083	Historic Fluted	$19.05	N/I
430	Acorn	9,500	0.117	Historic Fluted	$27.04	N/I
466	Colonial	4,000	0.060	Decorative Smooth	$12.18	I
412	Coach	5,800	0.083	Decorative Smooth	$36.74	I
413	Coach	9,500	0.117	Decorative Smooth	$36.99	I
467	Colonial	5,800	0.083	Decorative Smooth	$13.75	N/I
468	Colonial	9,500	0.117	Decorative Smooth	$14.00	
492	Contemporary	5,800	0.083	Fixture Only	$18.59	
476	Contemporary	5,800	0.083	Contemporary	$20.99	
497	Contemporary	9,500	0.117	Fixture Only	$18.36	
477	Contemporary	9,500	0.117	Contemporary	$25.80	
498	Contemporary	22,000*	0.242	Fixture Only	$21.46	
478	Contemporary	22,000*	0.242	Contemporary	$33.25	
499	Contemporary	50,000*	0.471	Fixture Only	$26.01	
479	Contemporary	50,000*	0.471	Contemporary	$40.97	
300	Dark Sky	4,000	0.060	Decorative Smooth	$26.83	
301	Dark Sky	9,500	0.117	Decorative Smooth	$27.98	

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 36.3

Standard Rate **RLS**

Restricted Lighting Service

TERMS AND CONDITIONS (Continued)

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: July 7, 2017

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 36.3

Standard Rate **RLS**

Restricted Lighting Service

T

DUE DATE OF BILL

Payment is due within sixteen (16) business days (no less than twenty-two (22) 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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	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 (5) 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: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Third Revision of Original Sheet No. 37
Canceling P.S.C. No. 18, Second 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
$0.07264 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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
Franchise Fee Rider	Sheet No. 90	
School Tax	Sheet No. 91	

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) 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: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 37

Standard Rate **LE**

Lighting Energy Service

APPLICABLE
In all territory served.

AVAILABILITY T
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
$0.07264 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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D/T
School Tax	Sheet No. 91	

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) 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: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Third Revision of Original Sheet No. 38
Canceling P.S.C. No. 18, 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, but not limited to, signals, cameras, or other traffic lights, electronic communication devices, and emergency sirens.

RATE

Basic Service Charge per month:	$4.00 per delivery point
Plus an Energy Charge per kWh:	$0.08955

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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
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 sixteen (16) business days (no less than twenty-two (22) 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.

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 38

Standard Rate **TE**

Traffic Energy Service

APPLICABLE
In all territory served.

AVAILABILITY T
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, but not limited to, signals, cameras, or other traffic lights, electronic communication devices, emergency sirens, and gunshot triangulation devices. N N

RATE

Basic Service Charge per day:	$0.13 per delivery point	T/R
Plus an Energy Charge per kWh:	$0.08955	

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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D/T
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 sixteen (16) business days (no less than twenty-two (22) 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.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 38.1

Standard Rate **TE**

Traffic Energy Service

CONDITIONS OF SERVICE (continued)

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: July 7, 2017

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 38.1

Standard Rate **TE**

Traffic Energy Service

CONDITIONS OF SERVICE (continued)

2. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and Customer. Where attachment of Customer's devices is made to Company facilities, Customer must have an attachment agreement with Company. T

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: September 28, 2018

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. Electric No. 18, Original Sheet No. 40

T

Standard Rate **PSA**

Pole and Structure Attachment Charges

APPLICABLE

In all territory served.

AVAILABILITY

Available to the facilities of cable television system operators and telecommunications carriers as provided below except: (1) facilities of incumbent local exchange carriers ("ILECs") with joint use agreements with the Company; (2) facilities subject to a fiber exchange agreement; and (3) Macro Cell Facilities. Nothing in this tariff expands the right to attach to the Company's structures beyond the rights otherwise conveyed by law.

APPLICABILITY OF SCHEDULE TO CURRENT LICENSE AGREEMENTS

Any telecommunication carrier that executed a license agreement permitting attachments to the Company's structures prior to the effective date of this Schedule shall be subject to the rates, terms, and conditions of this Schedule upon expiration or termination of its license agreement**.**

DEFINITIONS

"Affiliate" means, with respect to an entity, any entity controlling, controlled by, or under common control with such entity.

"Approved Contractor" means a contractor approved by Company for a particular purpose.

"Attachment" means the Cable or Wireless Facilities and all associated appliances including without limitation any overlashed cable, guying, small splice panels and vertical overhead to underground risers but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or otherwise conflicts with Company's electric design and construction standards.

"Attachment Customer" means a customer that attaches its facilities to one or more of the Company's Structures and has executed an Attachment Customer Agreement with the Company.

"Attachment Customer Agreement" means the written agreement provided by the Company and executed between Attachment Customer and Company incorporating the terms and conditions of this Schedule.

"Business Day" means a calendar day unless it is a Saturday, a Sunday or a legal holiday.

"Cable" means the fiber optic or coaxial cable, or any other type of cable, as well as any messenger wire or support strand.

"Cable television system operator" means a Person who operates a system that transmits television signals, for distribution to subscribers of its services for a fee, by means of wires or cables connecting its distribution facilities with its subscriber's television receiver or other

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 40

T

Standard Rate **PSA**

Pole and Structure Attachment Charges

APPLICABLE

In all territory served.

AVAILABILITY

Available to the facilities of Governmental units, Educational Institutions, Cable Television System Operators and Telecommunications Carriers as provided below except: (1) facilities of local exchange carriers ("ILECs") with joint use agreements with Company; (2) facilities subject to a fiber exchange agreement; and (3) Macro Cell Facilities. Nothing in this tariff expands the right to attach to Company's structures beyond the rights otherwise conveyed by law.

APPLICABILITY OF SCHEDULE TO CURRENT LICENSE AGREEMENTS

Any Telecommunications Carrier that executed a license agreement permitting attachments to Company's Structures prior to the July 1, 2017 shall be subject to the rates, terms, and conditions of this Pole and Structure Attachment Charges Schedule ("this Schedule") upon expiration or termination of its license agreement**.** Any Governmental Unit or Educational Institution that executed a license agreement permitting attachments to Company's Structures prior to May 1, 2019 shall be subject to the rates, terms and conditions of this Schedule upon expiration or termination of its license agreement, unless such license agreement provides otherwise.

DEFINITIONS

"Affiliate" means, with respect to an entity, any entity controlling, controlled by, or under common control with such entity.

"Approved Contractor" means a contractor approved by Company for a particular purpose.

"Attachment" means the Cable or Wireless Facilities and all associated appliances including without limitation any overlashed cable, guying, small splice panels and vertical overhead to underground risers but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or otherwise conflicts with Company's electric design and construction standards.

"Attachment Customer" means a Customer that attaches its facilities to one or more of Company's Structures and has executed a Contract for Attachment to Company Structures with Company.

"Contract for Attachment to Company Structures" or "Contract" means the written agreement provided by Company and executed between Attachment Customer and Company incorporating the terms and conditions of this Schedule.

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On and After November 1, 2018

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. Electric No. 18, Original Sheet No. 40.1

Standard Rate **PSA**

Pole and Structure Attachment Charges

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equipment connecting to the subscriber's television receiver, and not by transmission of television signals through the air, and subscription to the system's service is available to the public.

"Communication Space" means the area below the Communication Worker Safety Zone to the limit of allowable NESC clearance, department of transportation or other governmental requirements, and Company's internal construction standards on poles.

"Communication Worker Safety Zone" means the space between the facilities located in the Supply Space and facilities located in the Communications Space on poles.

"Contractor" means any Person employed or engaged by Attachment Customer to perform work or render services upon or in the immediate vicinity of Company's Structures or associated facilities other than Attachment Customer and Attachment Customer's employees.

"Distribution Pole" means a utility pole supporting electric supply facilities, all of which operate at less than 69 kV, but does not include a non-wood street light pole or a wood street light pole that is not located in a public right-of-way.

"Duct" means a pipe, tube, conduit, manhole, or other structure made for supporting and protecting electric and/or communications wires or cables and in which wires, cables and conduits may be placed for support or protection but excluding (1) any pipe now or previously used for the transmission or distribution of natural gas, (2) any duct system supporting electric supply lines operated at 69kV or greater, and (3) any vault.

"High Volume Application" means an application or applications for Attachments to more than 300 poles or to place Cable or conduit through more than 10 manholes submitted to Company within a 30-day period.

"Macro Cell Facility" means a wireless communications system site that is typically high-power and high-site, and capable of covering a large physical area, as distinguished from a distributed antenna system (DAS), small cell, or WiFi attachment, by way of example. Macro Cell Facilities are typically, but not exclusively, co-located on Transmission Poles and communications monopoles and towers.

"Make Ready Survey" means a survey, in the form prescribed by the Company from time to time, prepared by the Company or an Approved Contractor describing in reasonable detail the make-ready engineering requirements, and such other information as the Company may require, for the installation of an Attachment or group of Attachments on a Structure or group of Structures.

"NEC" means the National Electrical Code.

"NESC" means the National Electrical Safety Code.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 40.1

Standard Rate **PSA**

Pole and Structure Attachment Charges

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"Business Day" means a calendar day unless it is a Saturday, a Sunday or a legal holiday.

"Cable" means the fiber optic or coaxial cable, or any other type of cable, as well as any messenger wire or support strand.

"Cable Television System Operator" means a Person who operates a system that transmits television signals, for distribution to subscribers of its services for a fee, by means of wires or cables connecting its distribution facilities with its subscriber's television receiver or other equipment connecting to the subscriber's television receiver, and not by transmission of television signals through the air, and subscription to the system's service is available to the public.

"Communication Space" means the area below the Communication Worker Safety Zone to the limit of allowable NESC clearance, department of transportation or other governmental requirements, and Company's internal construction standards on poles.

"Communication Worker Safety Zone" means the space between the facilities located in the Supply Space and facilities located in the Communications Space on poles.

"Contractor" means any Person employed or engaged by Attachment Customer to perform work or render services upon or in the immediate vicinity of Company's Structures or associated facilities other than Attachment Customer and Attachment Customer's employees.

"Credit Rating" means, with respect to any entity, the rating then assigned to such entity's unsecured, senior long-term debt obligations (not supported by third party credit enhancements) by Standard and Poor's Rating Group or its successor ("S&P"), or Moody's Investor Services, Inc. or its successor ("Moody's"), or if such entity does not have a rating for its senior unsecured long-term debt, then the rating then assigned to such entity as its "corporate credit rating" assigned by S&P, or the "long-term issuer rating" assigned by Moody's.

"Distribution Pole" means a utility pole supporting electric supply facilities, all of which operate at less than 69 kV, but does not include a non-wood street light pole or a wood street light pole that is not located in a public right-of-way.

"Duct" means a pipe, tube, conduit, manhole, or other structure made for supporting and protecting electric and/or communications wires or cables and in which wires, cables and conduits may be placed for support or protection but excluding (1) any pipe now or previously used for the transmission or distribution of natural gas, (2) any duct system supporting electric supply lines operated at 69kV or greater, and (3) any vault.

"Educational Institution" means a public or private, non-profit university, college or community college

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. Electric No. 18, Original Sheet No. 40.2

Standard Rate **PSA** T

Pole and Structure Attachment Charges

"Person" is defined by KRS 278.010(2).

"Service Drop" means a Cable, attached to a pole with a J-hook or other similar hardware that connects the trunk line to an end user's premises.

"Structure" means any Company pole, conduit, duct, or other facility normally used by the Company to support or protect its electric conductors but shall not include (1) any Transmission Pole other than Transmission Poles to which the Company has attached its own electric supply lines operated at less than 69kV; (2) any street light pole that is not a wood pole located in a public right-of-way; or (3) any pole that the Company has leased to a third party.

"Supply Space" means the space above the Communications Worker Safety Zone used for the installation of electric supply lines.

"Telecommunications carrier" means a Person who operates a system that (1) transmits by wire or wireless means, between or among points specified by the user, information of the user's choosing without change in the form or content of the information as sent or received, and (2) provides such transmission services for a fee directly to or for the public, or to such classes of users as to be effectively available directly to or for the public, and includes, but is not limited to, internet service providers, voice over internet protocol service providers, cellular and mobile phone service providers or resellers of such services.

"Transmission Pole" means any utility pole or tower supporting electric supply facilities designed to operate at 69 kV or greater.

"Wireless Facility" means, without limitation, antennas, risers, transmitters, receivers, and all other associated equipment used in connection with Attachment Customer's provision of wireless communications services and the transmission and reception of radiofrequency signals, but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or that conflicts with the Company's electric design and construction standards.

ATTACHMENT CHARGES

$ 7.25 per year for each wireline pole attachment.
$ 0.81 per year for each linear foot of duct.
$36.25 per year for each Wireless Facility located on the top of a Company pole.

The attachment charge for any other Wireless Facility shall be agreed upon by Attachment Customer and the Company and set forth in a special contract to be filed with the Commission.

BILLING

All attachment charges for use of Structures will be billed semi-annually based upon the type and number of Attachment Customer's Attachments reflected in Company's records on December 1

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 40.2 T

Standard Rate **PSA**

Pole and Structure Attachment Charges

"Governmental Unit" means an agency or department of the Federal Government, a department, agency, or other unit of the Commonwealth of Kentucky, a county or city, special district, or other political subdivision of the Commonwealth of Kentucky.

"High Volume Application" means an application or applications for Attachments to more than 300 poles or to place Cable or conduit through more than 10 manholes submitted to Company within a thirty (30) day period.

"Letter(s) of Credit means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch in a form acceptable to the Company. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit.

"Macro Cell Facility" means a wireless communications system site that is typically high-power and high-sited, and capable of covering a large physical area, as distinguished from a distributed antenna system (DAS), small cell, or WiFi attachment, by way of example. Macro Cell Facilities are typically, but not exclusively, co-located on Transmission Poles and communications monopoles and towers.

"Make-Ready Survey" means a survey, in the form prescribed by Company from time to time, prepared by Company or an Approved Contractor describing in reasonable detail the make-ready engineering requirements, and such other information as Company may require, for the installation of an Attachment or group of Attachments on a Structure or group of Structures.

"NEC" means the National Electrical Code.

"NESC" means the National Electrical Safety Code.

"Performance Assurance" means collateral in the form of cash, surety bond, Letter(s) of Credit, or other security acceptable to the Company.

"Person" is defined by KRS 278.010(2).

"Service Drop" means a Cable, attached to a pole with a J-hook or other similar hardware that connects the trunk line to an end user's premises.

"Structure" means any Company pole, conduit, duct, or other facility normally used by Company to support or protect its electric conductors but shall not include (1) any Transmission Pole with electric supply lines operated at 138kV or above; (2) any Transmission Pole with electric supply lines operated at less than 138kV other than Transmission Poles to which Company has also attached electric supply lines operated at less than 69kV; (3) any street light pole that is not a wood pole located in a public right-of-way; or (4) any pole that Company has leased to a third party.

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DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. Electric No. 18, Original Sheet No. 40.3

Standard Rate **PSA**

Pole and Structure Attachment Charges

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and June 1. A bill issued under this Schedule shall be due upon its issuance. Any bill not paid in full within 60 days of its issuance shall be assessed a late payment fee of 3 percent on the bill's current charges. If Attachment Customer fails to pay all charges and fees billed within six months of the bill's issuance, the Company may remove any or all of Attachment Customer's Attachments. In lieu of or in addition to removal of Attachments, the Company may exercise any other remedies available under law to address Attachment Customer's failure to make timely payment of any charges assessed under this Schedule.

TERM OF SERVICE

An executed Attachment Customer Agreement shall be for a term of 10 years and shall thereafter automatically renew for successive one year periods unless Company or Attachment Customer provides the other with written notice of termination at least 60 days prior to the renewal date.

TERMS AND CONDITIONS OF ATTACHMENT

Attachments to Company's Structures that do not interfere with the Company's electric service requirements and the Attachments of existing customers and joint users shall be permitted in accordance with the terms and conditions of this Schedule. The Terms and Conditions set forth in Section 5 of this Tariff shall also be applicable to the extent they are not in conflict with or inconsistent with this Schedule's provisions.

1. **ATTACHMENT CUSTOMER AGREEMENT**
   No Attachments shall be made to Company's Structures until Attachment Customer has executed an Attachment Customer Agreement. The Attachment Customer Agreement shall incorporate the terms and conditions set forth in this Schedule.

2. **NO PROPERTY RIGHTS**
   No use, however extended, of Company Structures shall create or vest in Attachment Customer any right, title or interest in the Structures. Attachment Customer Agreement confers only a non-exclusive right to affix and install Attachments to and on Company's Structures. The Company is not required to maintain any Structure for a period longer than demanded by its electric service requirements.

3. **USE OF COMPANY'S FACILITIES BY OTHERS**
   Nothing in this Schedule shall affect the rights or privileges previously conferred by the Company to others. The rights granted under this Schedule and the Attachment Customer Agreement shall at all times be subject to such previously conferred privileges and shall not affect the rights or privileges that may be conferred by the Company in the future to others.

4. **TRANSFER OF RIGHTS**
   Except as provided in this Schedule, Attachment Customer's rights under the Attachment Customer Agreement are non-delegable, non-transferable and non-assignable. Any delegation, transfer or assignment of any interest created by the Attachment Customer

DATE OF ISSUE: July 7, 2017

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 40.3

Standard Rate **PSA**

Pole and Structure Attachment Charges

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"Supply Space" means the space above the Communications Worker Safety Zone used for the installation of electric supply lines.

"Telecommunications carrier" means a Person who operates a system that (1) transmits by wire or wireless means, between or among points specified by the user, information of the user's choosing without change in the form or content of the information as sent or received, and (2) provides such transmission services for a fee directly to or for the public, or to such classes of users as to be effectively available directly to or for the public.

"Transmission Pole" means any utility pole or tower supporting electric supply facilities designed to operate at 69 kV or greater.

"Wireless Facility" means, without limitation, antennas, risers, transmitters, receivers, and all other associated equipment used in connection with Attachment Customer's provision of wireless communications services and the transmission and reception of radiofrequency signals, but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or that conflicts with Company's electric design and construction standards.

ATTACHMENT CHARGES

$ 7.25 per year for each wireline pole attachment.
$ 0.81 per year for each linear foot of duct.
$36.25 per year for each Wireless Facility located on the top of a Company pole.

The attachment charge for any other Wireless Facility shall be agreed upon by Attachment Customer and Company and set forth in a special contract to be filed with the Commission.

BILLING

All attachment charges for use of Structures will be billed semi-annually based upon the type and number of Attachment Customer's Attachments reflected in Company's records on December 1 and June 1. A bill issued under this Schedule shall be due upon its issuance. Any bill not paid in full within sixty (60) days of its issuance shall be assessed a late payment charge of three (3) percent on the bill's current charges. If Attachment Customer fails to pay all charges and fees billed within six (6) months of the bill's issuance, Company may remove any or all of Attachment Customer's Attachments. In lieu of or in addition to removal of Attachments, Company may exercise any other remedies available under law to address Attachment Customer's failure to make timely payment of any charges assessed under this Schedule.

DATE OF ISSUE: September 28, 2018

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

Standard Rate **PSA**

Pole and Structure Attachment Charges

T

Agreement or this Schedule without Company's prior written consent is voidable at the Company's option. Company shall not withhold its consent to Attachment Customer's delegation, transfer or assignment of rights under Attachment Customer Agreement upon notice of the delegation, transfer or assignment and adequate evidence is provided of Transferee's compliance with Term 23 (Insurance) and Term 24 (Performance Assurance).

Attachment Customer shall not permit a third party to overlash or utilize any Attachment without Company's prior written consent. Company may condition its consent upon such third party's compliance with all provisions of the Attachment Customer Agreement, this Schedule, and such other terms as Company may reasonably require.

5. COMPANY'S ABANDONMENT OF STRUCTURE

The Company shall provide an Attachment Customer with a minimum of 180 days' notice before abandoning a Structure to which Attachment Customer has made an Attachment unless state or local law, easement provisions, or contractual obligations to a third party requires the Structure to be abandoned in a shorter period, in which case the Company shall provide as much notice as is reasonably practicable.

6. FRANCHISES AND EASEMENTS

Attachment Customer shall secure at its own expense any right-of-way, easement, license, franchise or permit from any Person that may be required for the construction or maintenance of Attachments by or for Attachment Customer. If requested by Company, Attachment Customer shall submit to Company satisfactory evidence of such right-of-way, easement, license, franchise or permit. Company's approval of Attachments shall not constitute any representation or warranty regarding Attachment Customer's right to occupy or use any public or private right-of-way.

Upon an Attachment Customer's written request, the Company may provide to Attachment Customer such non-private information as the Company may have regarding the name of the record landowners from which the Company obtained easements for Structures. Such information is provided without representation or warranty as to its accuracy or completeness. The Company has no obligation to correct or supplement any information so provided. If the Company provides assistance to Attachment Customer in obtaining easements or other property rights, Attachment Customer shall reimburse the Company's cost of providing such assistance within 30 days of its receipt of an invoice from Company.

Attachment Customer shall indemnify and save harmless Company from all claims, including the expenses incurred by Company to defend itself against such claims, resulting from or arising out of the failure of Attachment Customer to secure any right of way, easement, license, franchise or permit.

DATE OF ISSUE: July 7, 2017

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

Standard Rate **PSA**

Pole and Structure Attachment Charges

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TERM OF SERVICE

An executed Contract shall be for a term of 10 (ten) years and shall thereafter automatically renew for successive one (1) year periods unless Company or Attachment Customer provides the other with written notice of termination at least sixty (60) days prior to the renewal date.

TERMS AND CONDITIONS OF ATTACHMENT

Attachments to Company's Structures that do not interfere with Company's electric service requirements and the Attachments of existing Customers and joint users shall be permitted in accordance with the terms and conditions of this Schedule. The Terms and Conditions set forth in Section 5 of the Company's Electric Service Tariff shall also be applicable to the extent they are not in conflict with or inconsistent with this Schedule's provisions.

1. CONTRACT FOR ATTACHMENT TO COMPANY STRUCTURES

No Attachments shall be made to Company's Structures until Attachment Customer has executed a Contract for Attachment to Company Structures, in a form substantially similar to that which is included at the end of this Schedule.. The Contract shall incorporate the terms and conditions set forth in this Schedule.

2. NO PROPERTY RIGHTS

No use, however extended, of Company Structures shall create or vest in Attachment Customer any right, title or interest in the Structures. A Contract confers only a non-exclusive right to affix and install Attachments to and on Company's Structures. Company is not required to maintain any Structure for a period longer than demanded by its electric service requirements.

3. USE OF COMPANY'S FACILITIES BY OTHERS

Nothing in this Schedule shall affect the rights or privileges previously conferred by Company to others. The rights granted under this Schedule and the Contract shall at all times be subject to such previously conferred privileges and shall not affect the rights or privileges that may be conferred by Company in the future to others.

4. TRANSFER OF RIGHTS

Except as provided in this Schedule, Attachment Customer's rights under the Contract are non-delegable, non-transferable and non-assignable. Any delegation, transfer or assignment of any interest created by the Contract or this Schedule without Company's prior written consent is voidable at Company's option. Company shall not unreasonably withhold its consent to Attachment Customer's delegation, transfer or assignment of rights under the Contract upon notice of the delegation, transfer or assignment and if adequate evidence is provided of transferee's compliance with Term 23 (Insurance) and Term 24 (Performance Assurance).

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

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7. ATTACHMENT APPLICATIONS AND PERMITS

a. Unless waived by the Company, Attachment Customer shall make written application, in the form and manner prescribed by the Company for permission to install Attachments on or in any Structure. Each application shall include: (1) in the case of poles, the owner, number and location of all Structures for which license to attach is sought and the amount of space required thereon; (2) in the case of Ducts, the number of linear feet of Duct space and the specific location of each such Duct to be utilized, the amount of requested space, the nature of any changes or inner Duct or Ducts proposed to be installed and any other construction that might be required by the proposed Attachments; (3) the physical attributes of all proposed Attachments; (4) the proposed start date for installation of the Attachments; (5) any issues then known to Attachment Customer regarding space, engineering, access or other matters that might require resolution before installation of Attachments; and (6) proposed make ready drawings. Company may request additional information be included with the application at its reasonable discretion. Company may perform a pole loading study or request Attachment Customer to submit such study based upon a visual inspection or other information held by Company. If Company conducts a visual inspection of the pole to ascertain the need for a pole loading analysis, Company may assess the cost of such inspection to the Attachment Customer. If Company determines a pole loading study is required, no application shall be considered filed until submission of such study. Attachment Customer may perform the pole loading study or request Company to perform the study with cost to be borne by Attachment Customer. Nothing contained herein shall preclude Attachment Customer from submitting a pole loading study with its application without Company performing a visual inspection or otherwise requesting such study to expedite Company's review.

b. Attachment Customer shall be responsible for all costs associated with the application, a Make Ready Survey, engineering analysis, and the Company's review of the application. Attachment Customer shall reimburse Company upon presentation of an invoice for such costs. If Attachment Customer does not request Attachments to a Transmission Pole or Duct, Company shall complete a Make Ready Survey within 60 days of its receipt of Attachment Customer's completed application. If Attachment Customer's application requests attachments to a Transmission Pole or Duct, Attachment Customer and Company shall mutually agree to a time period for performance.

c. Upon completion of the Make Ready Survey, the Company shall notify Attachment Customer in writing whether its application for use of Company's Structures has been granted, of any necessary changes to the proposed construction drawings, and the conditions, if any, imposed on the installation or use of Attachments. The Company reserves the right to deny access to any Structure based upon lack of capacity, safety, reliability or engineering standards. The Company may deny access to Transmission Poles in its discretion for any reason; provided that such denials shall be determined in

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Attachment Customer shall not permit a third party to overlash or utilize any Attachment without Company's prior written consent. Company may condition its consent upon such third party's compliance with all provisions of the Contract, this Schedule, and such other terms as Company may reasonably require.

5. COMPANY'S ABANDONMENT OF STRUCTURE

Company shall provide an Attachment Customer with a minimum of 180 days' notice before abandoning a Structure to which Attachment Customer has made an Attachment unless state or local law, easement provisions, or contractual obligations to a third party requires the Structure to be abandoned in a shorter period, in which case Company shall provide as much notice as is reasonably practicable.

6. FRANCHISES AND EASEMENTS

Attachment Customer shall secure at its own expense any right-of-way, easement, license, franchise or permit from any Person that may be required for the construction or maintenance of Attachments by or for Attachment Customer. If requested by Company, Attachment Customer shall submit to Company satisfactory evidence of such right-of-way, easement, license, franchise or permit. Company's approval of Attachments shall not constitute any representation or warranty regarding Attachment Customer's right to occupy or use any public or private right-of-way.

Upon an Attachment Customer's written request, Company may provide to Attachment Customer such non-private information as Company may have regarding the name of the record landowners from which Company obtained easements for Structures. Such information is provided without representation or warranty as to its accuracy or completeness. Company has no obligation to correct or supplement any information so provided. If Company provides assistance to Attachment Customer in obtaining easements or other property rights, Attachment Customer shall reimburse Company's cost of providing such assistance within thirty (30) days of its receipt of an invoice from Company.

Attachment Customer shall indemnify and save harmless Company from all claims, including the expenses incurred by Company to defend itself against such claims, resulting from or arising out of the failure of Attachment Customer to secure any right of way, easement, license, franchise or permit.

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P.S.C. Electric No. 18, Original Sheet No. 40.6

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a non-discriminatory manner. Transmission Poles that do not support electric supply lines operated at less than 69kV are not available for Attachments under this Schedule.

d. Within 15 days of notifying Attachment Customer of the approval of its application, Company shall provide Attachment Customer a written statement of the costs of any necessary Company make-ready work, including but not limited to rearrangement of electric supply facilities and pole change out. Attachment Customer shall indicate its approval of this statement by submitting payment of the statement amount within 15 days of receipt. If facilities of a third party are required to be rearranged or transferred, Attachment Customer shall coordinate with the third party for such rearrangement or transfer and shall pay the costs related thereto. If Attachment Customer's application requests attachments to a Transmission Pole or Duct, Attachment Customer and Company shall mutually agree to a time period for preparation of a written statement of the costs of any necessary Company make-ready work.

e. If an existing Structure is replaced or a new Structure is erected solely to provide adequate capacity for Attachment Customer's proposed Attachments, Attachment Customer shall pay a sum equal to the actual material and labor cost of the new Structure, as well as any replaced appurtenances, plus the cost of removal of the existing Structure minus its salvage value, within 30 days of receipt of an invoice. The new Structure shall be Company's property regardless of any Attachment Customer payments toward its cost. Attachment Customer shall acquire no right, title or interest in or to such Structure.

f. If Company is unable to perform the Make Ready Survey and engineering analysis within the time period established under Section 7b, it shall advise Attachment Customer and promptly meet with Attachment Customer to develop a mutually agreeable plan of performance.

g. If Company fails to perform the make-ready work within 60 days of receipt of Attachment Customer's payment of the make-ready costs, Attachment Customer may perform such work at its expense using an Approved Contractor, except that Attachment Customer may not perform such work with respect to Transmission Poles or Ducts. Company shall refund any unexpended make-ready fees within 30 days of notice that Attachment Customer has performed the work. Attachment Customer shall notify Company upon completion of such make-ready work and Company may inspect such work prior to the construction of Attachments. Attachment Customer shall bear the cost of such Company inspection.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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P.S.C. No. 19, Original Sheet No. 40.6

Standard Rate **PSA**

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7. ATTACHMENT APPLICATIONS AND PERMITS

a. Unless waived by Company, Attachment Customer shall make written application, in the form and manner prescribed by Company for permission to install Attachments on or in any Structure. Each application shall include: (1) in the case of poles, the owner, number and location of all Structures for which license to attach is sought and the amount of space required thereon; (2) in the case of Ducts, the number of linear feet of Duct space and the specific location of each such Duct to be utilized, the amount of requested space, the nature of any changes or inner Duct or Ducts proposed to be installed and any other construction that might be required by the proposed Attachments; (3) the physical attributes of all proposed Attachments; (4) the proposed start date for installation of the Attachments; (5) any issues then known to Attachment Customer regarding space, engineering, access or other matters that might require resolution before installation of Attachments; and (6) proposed make ready drawings. Company may request additional information be included with the application at its reasonable discretion. Company may perform a pole loading study or request Attachment Customer to submit such study based upon a visual inspection or other information held by Company. If Company conducts a visual inspection of the pole to ascertain the need for a pole loading analysis, Company may assess the cost of such inspection to the Attachment Customer. If Company determines a pole loading study is required, no application shall be considered completed until submission of such study. Attachment Customer may perform the pole loading study or request Company to perform the study with cost to be borne by Attachment Customer. Nothing contained herein shall preclude Attachment Customer from submitting a pole loading study with its application without Company performing a visual inspection or otherwise requesting such study to expedite Company's review.

b. Attachment Customer shall be responsible for all costs associated with the application, a Make Ready Survey, engineering analysis, and Company's review of the application. Attachment Customer shall reimburse Company upon presentation of an invoice for such costs. If Attachment Customer does not request Attachments to a Transmission Pole or Duct, Company shall complete a Make Ready Survey within sixty (60) days of its receipt of Attachment Customer's completed application. If Attachment Customer's application requests Attachments to a Transmission Pole or Duct, Attachment Customer and Company shall mutually agree to a time period for completion of a Make-Ready Survey.

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h. If Attachment Customer submits to Company within a 30-day period an application or applications for Attachments to more than 300 poles or to place Cable or conduit through more than 10 manholes, such application or applications shall be considered a High Volume Application. The provisions set forth in Sections 7b through 7g that relate to time period and cost-reimbursement of the Company's performance of application review, engineering analysis, and a Make Ready Survey, and the performance of make-ready work, shall not apply to High Volume Applications. The Company and Attachment Customer submitting a High Volume Application shall develop a mutually agreeable plan of performance and cost reimbursement for Company's performance of application review, engineering analysis, and a Make Ready Survey, and the performance of make ready work, shall set this plan to writing and shall file it with the Commission as a special contract.

i. No written application to the Company to affix and attach a service drop to the Company's poles is required but Attachment Customer shall provide notice to the Company of such attachment within 60 days of attachment. This notice shall include the attachment location address (or a description of the location if the address is not available), the date of the attachment, the pole number of the pole to which the service drop is affixed or attached, and a statement as to whether the attachment constitutes a new attachment to the Company's pole. All pole contacts by Attachment Customer that are contained within one foot of usable space of Company's pole shall be considered as a single wireline attachment. All pole contacts by Attachment Customer that are contained within one foot of space on a Company drop or lift pole shall also be considered as a separate single wireline attachment. All pole contacts (attachment of horizontal wires or strands) not contained within one foot of usable space on a Company pole shall be considered as a separate attachment. The provisions of this Pole Structure Attachment Schedule shall not apply to an ILEC service drop if the ILEC has a joint use agreement with the Company and the service drop is located in the area covered by the joint use agreement.

8. CONSTRUCTION AND MAINTENANCE REQUIREMENTS AND SPECIFICATIONS

a. Attachment Customer shall not construct or install any Attachments until Company has approved in writing the design, construction, and installation practices for Attachment Customer's Attachments.

b. All Attachments shall be constructed and installed in a manner reasonably satisfactory to Company and so as not to interfere with the Company's present or future use of its Structures. Attachments in Ducts shall not include any splice enclosures or excess cable. Attachment Customer shall maintain, operate and construct all Attachments in such manner as to ensure Company's full and free access to all Company facilities. All Attachments shall conform to Company's electric design and construction standards and applicable requirements of the NESC, NEC, and all other applicable codes and laws. In the event of a conflict, the more stringent standard shall apply.

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Lexington, Kentucky

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Kentucky Utilities Company

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c. Upon completion of the Make Ready Survey, Company shall notify Attachment Customer in writing whether its application for use of Company's Structures has been granted, of any necessary changes to the proposed construction drawings, and the conditions, if any, imposed on the installation or use of Attachments. Company reserves the right to deny access to any Structure based upon lack of capacity, safety, reliability or engineering standards. Company may deny access to Transmission Poles in its discretion for any reason; provided that such denials shall be determined in a non-discriminatory manner. The following types of Transmission Poles that do not support electric supply lines operated at less than 69kV are not available for Attachments under this Schedule: (1) Transmission Poles that do not support electric supply lines operated at less than 69kV; (2) any Transmission Poles that support electric supply lines operated at 138kV or above.

d. Within fifteen (15) days of notifying Attachment Customer of the approval of its application, Company shall provide Attachment Customer a written statement of the costs of any necessary Company make-ready work, including but not limited to rearrangement of electric supply facilities and pole change out. Attachment Customer shall indicate its approval of this statement by submitting payment of the statement amount within fifteen (15) days of receipt. If facilities of a third party are required to be rearranged or transferred, Attachment Customer shall coordinate with the third party for such rearrangement or transfer and shall pay the costs related thereto. If Attachment Customer's application requests attachments to a Transmission Pole or Duct, Attachment Customer and Company shall mutually agree to a time period for preparation of a written statement of the costs of any necessary Company make-ready work.

e. If an existing Structure is replaced or a new Structure is erected solely to provide adequate capacity for Attachment Customer's proposed Attachments, Attachment Customer shall pay a sum equal to the actual material and labor cost of the new Structure, as well as any replaced appurtenances, plus the cost of removal of the existing Structure minus its salvage value, within thirty (30) days of receipt of an invoice. The new Structure shall be Company's property regardless of any Attachment Customer payments toward its cost. Attachment Customer shall acquire no right, title or interest in or to such Structure.

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Kentucky Utilities Company

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c. Attachment Customer shall identify each of its Attachments with a tag, approved in advance by Company, that includes Attachment Customer's name, 24-hour contact telephone number, and such other information as Company may require. Attachment Customer shall tag an Attachment at the time of construction. Any untagged Attachment existing as of the date of execution of Attachment Customer Agreement or the effective date of this Schedule, whichever is earlier, shall be tagged when Attachment Customer or its agents perform work on the Attachment. All Cable placed by Attachment Customer within a Company-owned or controlled Duct shall be enclosed within Attachment Customer furnished inner-duct and shall be clearly marked and identified as belonging to Attachment Customer at all access points. Service drops do not need to be tagged.

d. In the design, installation and maintenance of its Attachments, Attachment Customer shall comply with all Company standards and all federal, state and local government laws, rules, regulations, ordinances, or other lawful directives applicable to the work of constructing and installing the Attachments. All work shall be performed in accordance with the applicable standards of the NESC and the NEC, including amendments thereto adopted. Attachment Customer shall take all necessary precautions, by the installation of protective equipment or other means, to protect all Persons and property of all kinds against injury or damage caused by or occurring by reason of the construction, installation or existence of Attachments.

e. Attachment Customer shall immediately report to Company (1) any damage caused to property of Company or others when installing or maintaining Attachments, (2) any Attachment Customer's failure to meet the requirements set forth in this Schedule for assuring the safety of Persons and property and compliance with laws and regulations of public authorities and standard-setting bodies, and (3) any unsafe condition relating to Company's Structures identified by Attachment Customer.

f. Attachment Customer shall complete installation of its Attachments within 60 days of the later of approval of the application for such Attachments or, if make-ready work is required under such approval, completion of make-ready work, and shall notify Company in writing upon its completion. If Attachment Customer fails to complete the installation within this time period, the Company may revoke its permit for the Attachment. Prior to revoking the permit for the Attachment, Company shall provide written notice of the revocation to Attachment Customer. Company may conduct an inspection of such Attachments. Attachment Customer shall reimburse Company within 30 days of presentation of an invoice for such inspections.

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f. If Company is unable to perform the Make Ready Survey and engineering analysis within the time period established under Section 7b, Company shall advise Attachment Customer and promptly meet with Attachment Customer to develop a mutually agreeable plan of performance.

g. If Company fails to perform the make-ready work within sixty (60) days of receipt of Attachment Customer's payment of the make-ready costs, Attachment Customer may perform such work at its expense using an Approved Contractor, except that Attachment Customer may not perform such work with respect to Transmission Poles or Ducts.. The Approved Contractor shall provide notice to Company at least one week prior to performing any make-ready. During the performance of any make-ready by Approved Contractors, an inspector designated by Company shall accompany the Approved Contractor(s). The inspector, in his or her sole discretion, may direct that work be performed in a manner other than as approved in an application, based on the then-existing circumstances in the field. The cost of such inspector(s) shall be reimbursed by Attachment Customer within 30 days of receipt of an invoice from Company. Company shall refund any unexpended make-ready fees within 30 days of notice that Attachment Customer has performed the work.

h. If Attachment Customer submits to Company within a thirty (30) day period an application or applications for Attachments to more than 300 poles or to place Cable or conduit through more than ten (10) manholes, such application or applications shall be considered a High Volume Application. The provisions set forth in Sections 7b through 7g that relate to time period and cost-reimbursement of Company's performance of application review, engineering analysis, and a Make Ready Survey, and the performance of make-ready work, shall not apply to High Volume Applications. Company and Attachment Customer submitting a High Volume Application shall develop a mutually agreeable plan of performance and cost reimbursement for Company's performance of application review, engineering analysis, and a Make Ready Survey, and the performance of make ready work, shall set this plan to writing and shall file it with the Commission as a special contract.

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g. Company may monitor Attachment Customer's construction and installation of Attachments. If the need for a monitor is caused by Attachment Customer's failure to comply with the terms of this Schedule, the Attachment Customer Agreement, or any applicable law or regulation, Attachment Customer shall reimburse Company for the actual cost of any such monitoring within 30 days of receipt of an invoice for such cost. For locations where Attachment Customer's construction and installation are within Company underground facilities, Attachment Customer shall reimburse Company for the actual cost associated with providing inspection services within 30 days of receipt of an invoice.

h. Attachment Customer may use qualified contractors of its own choice to perform work below the Communication Worker Safety Zone. For any work in or above the Communication Worker Safety Zone that Company allows Attachment Customer to perform, Attachment Customer shall use an Approved Contractor who may, at Company's discretion, be required to be accompanied by a Company-designated inspector. For any work in Company's Ducts, Attachment Customer shall use an Approved Contractor, who must be accompanied by a Company-designated inspector. The Company shall schedule a Company-designated inspector to accompany an Approved Contractor within 15 days of its receipt of such request for such inspector. The costs of such inspection shall be reimbursed to the Company in the same manner described in Section 8g above.

i. Attachment Customer shall comply with all applicable Federal, State, and local laws, rules and regulations with respect to environmental practices undertaken pursuant to the construction, installation, operation and maintenance of its Attachments. Attachment Customer shall not bring, store or utilize any hazardous materials on any Company site without the Company's prior express written consent. To the extent reasonably practicable, Attachment Customer shall restore any property altered pursuant to its performance under the Attachment Customer Agreement to its condition existing immediately prior to the alteration. Company has no obligation to correct or restore any property altered by Attachment Customer and bears no responsibility for Attachment Customer's compliance with applicable environmental regulations.

j. If Attachment Customer fails to install any Attachment in accordance with the standards and terms set forth in this Schedule and Company provides written notice to Attachment Customer of such failure, Attachment Customer, at its own expense, shall make necessary adjustments within 30 days of receipt of such notice. Subject to Section 15 of this Schedule, if Attachment Customer fails to make such adjustments within such time period, Company may make the repairs or adjustments, and Attachment Customer shall pay Company for the actual cost thereof within 30 days of receipt of an invoice.

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i. No written application to Company to affix and attach a Service Drop to Company's poles is required but Attachment Customer shall provide notice to Company within sixty (60) days of attachment of such Service Drop. This notice shall include the Service Drop location address (or a description of the location if the address is not available), the date of the attachment, the pole number of the pole to which the Service Drop is affixed or attached, and a statement as to whether the Service Drop constitutes a new Attachment to Company's pole for billing purposes. Any Service Drop affixed to a pole more than six (6) inches above or below a through-bolt shall be considered a separate Attachment for billing purposes. On drop or lift poles only, all Service Drops affixed within one foot of usable space shall be considered a single Attachment for billing purposes. Company may conduct an inspection of any Service Drop Attachments, and Attachment Customer shall reimburse Company within 30 days of presentation of an invoice for such inspections. The provisions of this Pole Structure Attachment Schedule shall not apply to an ILEC service drop if the ILEC has a joint use agreement with the Company and the service drop is located in the area covered by the joint use agreement.

8. CONSTRUCTION AND MAINTENANCE REQUIREMENTS AND SPECIFICATIONS

a. Attachment Customer shall not construct or install any Attachments until : (1) Company has approved in writing the design, construction, and installation practices for Attachment Customer's Attachments; (2) all Company make-ready work, if any, has been completed (and, if such make-ready work has been performed by an Approved Contractor pursuant to Section 7g above, inspected by Company); and (3) any necessary third party rearrangements or transfers have been completed. Any Attachment that fails to comply with this provision shall be deemed an Unauthorized Attachment for purposes of Section 19 of this Schedule

b. All Attachments shall be constructed and installed in a manner reasonably satisfactory to Company and so as not to interfere with Company's present or future use of its Structures. Attachments in Ducts shall not include any splice enclosures or excess cable. Attachment Customer shall maintain, operate and construct all Attachments in such manner as to ensure Company's full and free access to all Company facilities. All Attachments shall conform to Company's electric design and construction standards and applicable requirements of the NESC, NEC, and all other applicable codes and laws. In the event of a conflict, the more stringent standard shall apply.

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k. Attachment Customer is responsible for any damage, fines or penalties resulting from any noncompliance with the construction and maintenance requirements and specifications set forth in this Section 8, except when Attachment Customer demonstrates that noncompliance is due to the actions of the Company or another Attachment Customer. Company undertakes no duty to require any specific action by Attachment Customer and assumes no responsibility by requiring such compliance or by requiring Attachment Customer to meet any specifications or to make any corrections, modifications, additions or deletions to any work or planned work by Attachment Customer.

l. Within 15 days of completion of the installation of the Attachment, Attachment Customer shall furnish Company with complete "as-built" drawings in a computer generated electronic format (or such other format as is agreeable to Company). Hand drawings shall not be submitted.

9. ADDITIONAL REQUIREMENTS FOR WIRELESS FACILITIES

a. Wireless Facilities Attachments may be attached to Distribution Poles only.

b. Company may require Attachment Customer to furnish with any written application for permission to install a Wireless Facilities Attachment a mock-up of the proposed Attachment.

c. Attachment Customer is solely responsible for ensuring that the radiofrequency ("RF") radiation emitted by its Wireless Facilities, alone and/or in combination with any and all sources of RF radiation in the vicinity, is within the limits permitted under all applicable governmental and industry standard safety codes for general population/uncontrolled exposure. Attachment Customer shall install appropriate signage on the poles to which Wireless Facilities have been attached, to warn line workers or the general public of the presence of RF radiation and the need for precautionary measures. Attachment Customer shall periodically inspect the signage and replace the signage if necessary to ensure that the signage, including text and warning symbols, remains clearly visible.

d. Each Wireless Facility installation shall include a switch that operates to disconnect and de-energize the antenna. In non-emergency circumstances, Company employees or contractors will make reasonable efforts to contact Attachment Customer at a telephone number that Attachment Customer has marked on the Wireless Facility installation to request a temporary power shut-down. Company personnel or those of other attaching entities will operate the power disconnect switch to ensure that the antenna is not energized while work on the pole is in progress. In emergency circumstances, Company personnel and those of other entities attached to Company poles may accomplish the power-down by operation of the power disconnect switch without advance notice to Attachment Customer.

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c. Attachment Customer shall identify each of its Attachments with a tag, approved in advance by Company, that includes Attachment Customer's name, 24-hour contact telephone number, and such other information as Company may require. All Cable placed by Attachment Customer within a Company-owned or controlled Duct shall be enclosed within Attachment Customer furnished inner-duct and shall be clearly marked and identified as belonging to Attachment Customer at all access points. Service drops do not need to be tagged. Attachment Customer shall tag an Attachment at the time of construction. Any untagged Attachment existing as of the date of execution of the Contract or the effective date of this Schedule, whichever is earlier, shall be tagged by Attachment Customer when Attachment Customer or its agents perform work on the Attachment. . If the Company is required to relocate or remove an Attachment or otherwise contact the owner of an Attachment to effect repairs and the Attachment is untagged and cannot be readily identified, any expense incurred by Company to identify the Attachment owner shall be borne by the Attachment Customer. Further, the Company shall be considered to have provided notice to the owner of an untagged Attachment required under Section 16 of this Schedule upon inspecting the Attachment and determining that it is untagged.

d. In the design, installation and maintenance of its Attachments, Attachment Customer shall comply with all Company standards and all federal, state and local government laws, rules, regulations, ordinances, or other lawful directives applicable to the work of constructing and installing the Attachments. All work shall be performed in accordance with the applicable standards of the NESC and the NEC, including amendments thereto adopted. Attachment Customer shall take all necessary precautions, by the installation of protective equipment or other means, to protect all Persons and property of all kinds against injury or damage caused by or occurring by reason of the construction, installation or existence of Attachments.

e. Attachment Customer shall immediately report to Company (1) any damage caused to property of Company or others when installing or maintaining Attachments, (2) any Attachment Customer's failure to meet the requirements set forth in this Schedule for assuring the safety of Persons and property and compliance with laws and regulations of public authorities and standard-setting bodies, and (3) any unsafe condition relating to Company's Structures identified by Attachment Customer.

f. Attachment Customer shall complete installation of its Attachments within sixty (60) days of the later of approval of the application for such Attachments or, if make-ready work is required under such approval, completion of make-ready work, and shall notify Company in writing upon its completion. If Attachment Customer fails to complete the installation within this time period, Company may revoke its permit for the Attachment. Prior to revoking the permit for the Attachment, Company shall provide written notice of the revocation to Attachment Customer. Company may conduct a post-construction inspection of such Attachments. Attachment Customer shall reimburse Company within thirty (30) days of presentation of an invoice for such inspections.

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e. Attachment Customer is solely responsible for ensuring compliance with all Federal Communication Commission antenna registration requirements, Federal Aviation Administration air hazard requirements, or similar requirements with respect to the location of Attachment Customer's Wireless Facilities on Company's poles.

f. All power supplies, equipment cabinets, meter bases and other equipment associated with the Wireless Facilities that are large enough to impede accessibility shall be installed off-pole, consistent with the applicable standards of the NESC, Company standards, and all applicable laws, rules, regulations, ordinances, and other applicable governmental directives.

10. OVERLASHING OF CABLE

An Attachment Customer may make an initial overlash of an existing attachment if the overlash is not greater than one-half inch in diameter without any advance notice or application to the Company. No application or advance notice is required for the replacement of an existing cable with a cable that is no greater than one-half inch in diameter. With all other overlashing, Attachment Customer shall provide the Company with advance notice to permit the Company to visually inspect its Structures to determine the need for a pole loading analysis. For projects involving more than 10 spans, the Attachment Customer must provide at least 15 business days' advance notice. For projects involving 10 spans or less, Attachment Customer shall provide at least 7 business days' advance notice. Notwithstanding the foregoing, no bundle of Attachment Customer's Cable shall exceed two inches in diameter without Company's express written approval.

11. STRAND-MOUNTED WIRELESS COMMUNICATION DEVICES

A strand-mounted wireless communication device shall be considered part of wireline attachment and not subject to permitting or an additional attachment charge if it is located within the one foot vertical space occupied by Attachment Customer's cable and meets all applicable loading, clearance, and RF emission requirements. Before deploying any strand-mounted wireless communications devices other than strand-mounted wi-fi access points, Attachment Customer shall at least 60 days prior to planned deployment notify the Company of the proposed deployment and provide sufficient information regarding the nature of device to permit the Company to assess the safety and loadbearing implications of the proposed deployment.

12. MAINTENANCE OF ATTACHMENTS AND STRUCTURES

Attachment Customer shall maintain Attachments in safe condition and in good repair, in a manner reasonably suitable to Company and so as not to conflict with any use of Company facilities (including Structures) by Company or any other Person using such facilities pursuant to any license or permit by Company. Attachment Customer shall not interfere with the

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g. Attachment Customer may use qualified contractors of its own choice to perform work below the Communication Worker Safety Zone. For any work in or above the Communication Worker Safety Zone that Company allows Attachment Customer to perform, Attachment Customer shall use an Approved Contractor who may, at Company's discretion, be required to be accompanied by a Company-designated inspector. For any work in Company's Ducts, Attachment Customer shall use an Approved Contractor, who must be accompanied by a Company-designated inspector. Company shall schedule a Company-designated inspector to accompany an Approved Contractor within fifteen (15) days of its receipt of such request for such inspector. Attachment Customer shall reimburse Company for the actual cost associated with providing inspection services within 30 days of receipt of an invoice.

h. Company may also monitor Attachment Customer's construction and installation of Attachments below the Communication Worker Safety Zone. If the need for a monitor is caused by Attachment Customer's failure to comply with the terms of this Schedule, the Contract, or any applicable law or regulation, Attachment Customer shall reimburse Company for the actual cost of any such monitoring within thirty (30) days of receipt of an invoice for such cost. For locations where Attachment Customer's construction and installation are within Company underground facilities, Attachment Customer shall reimburse Company for the actual cost associated with providing inspection services within thirty (30) days of receipt of an invoice.

i. Attachment Customer shall comply with all applicable federal, state, and local laws, rules and regulations with respect to environmental practices undertaken pursuant to the construction, installation, operation and maintenance of its Attachments. Attachment Customer shall not bring, store or utilize any hazardous materials on any Company site without Company's prior express written consent. To the extent reasonably practicable, Attachment Customer shall restore any property altered pursuant to this Schedule or the Contract to its condition existing immediately prior to the alteration. Company has no obligation to correct or restore any property altered by Attachment Customer and bears no responsibility for Attachment Customer's compliance with applicable environmental regulations.

j. If Attachment Customer fails to install any Attachment in accordance with the standards and terms set forth in this Schedule and Company provides written notice to Attachment Customer of such failure, Attachment Customer, at its own expense, shall make necessary adjustments within thirty (30) days of receipt of such notice. Subject to Section 15 of this Schedule, if Attachment Customer fails to make such adjustments within such time period, Company may make the repairs or adjustments, and Attachment Customer shall pay Company for the actual cost thereof plus a penalty of 50% of actual costs within thirty (30) days of receipt of an invoice.

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working use of any other Person's property on or in such facilities or any such property, which may be placed on or near the Structures and other facilities. Company reserves to itself, its successors, Affiliates and assigns, the right to maintain Structures and other Company property and to operate its business and maintain its property in such a manner as will, in its own judgment, best enable it to fulfill its own service requirements. Company shall not be liable to Attachment Customer for any interference with the operation of Attachment Customer's facilities, or loss of business arising in any manner out of the use of Company's Structures or other property.

13. NATIONAL JOINT UTILITIES NOTIFICATION SYSTEM

Within 30 days of executing Attachment Customer Agreement, and prior to making application for any Attachment, Attachment Customer will join National Joint Utilities Notification System ("NJUNS"), a web-based system developed to improve joint use communication, and will actively participate during the Term of Service, by entering field information into the NJUNS system within the times required by the system. Should Attachment Customer fail to actively participate in NJUNS and should such failure cause the Company to incur expense or liability to others, Attachment Customer shall reimburse the Company its expense and indemnify and hold the Company harmless from any damages or liability arising out of such failure. If Company at a later date elects to use a different web-based system for the joint use communication, it shall notify Attachment Customer at least sixty (60) days in advance of such change and Attachment Customer shall join that system.

14. INSPECTIONS/AUDITS

Company may make periodic inspections for the purpose of determining compliance with this Schedule and with the Attachment Customer Agreement. Neither the Company's right to make inspections nor any inspection made by Company shall relieve an Attachment Customer of any responsibility, obligation or liability assumed under this Schedule.

Upon thirty (30) days' prior notice to Attachment Customer, Company may conduct an audit of its Structures to verify the number, location and type of Attachment Customer's Attachments. Company shall make available to Attachment Customer the report of such audit. Such report shall indicate the location and pole number of all attachments of the Attachment Customer. If the audit reveals that the number of Attachments exceeds the number of attachments shown in Company's existing records, the excess number of Attachments shall be presumed to be Unauthorized Attachments. Attachment Customer shall have the right to rebut this presumption and demonstrate that the attachments at issue were authorized.

15. INTERFERENCE OR HAZARD

If Company notifies Attachment Customer in writing or orally with written confirmation that the Attachment Customer's Attachments or the condition of Attachment Customer's

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k. Attachment Customer is responsible for any damage, fines or penalties resulting from any noncompliance with the construction and maintenance requirements and specifications set forth in this Section 8, except when Attachment Customer demonstrates that noncompliance is due to the actions of Company or another Attachment Customer. Company undertakes no duty to require any specific action by Attachment Customer and assumes no responsibility by requiring such compliance or by requiring Attachment Customer to meet any specifications or to make any corrections, modifications, additions or deletions to any work or planned work by Attachment Customer.

l. Within fifteen (15) days of completion of the installation of the Attachment, Attachment Customer shall furnish Company with complete "as-built" drawings in a computer generated electronic format (or such other format as is agreeable to Company). Hand drawings shall not be submitted.

9. ADDITIONAL REQUIREMENTS FOR WIRELESS FACILITIES

a. Wireless Facilities Attachments may be attached to Distribution Poles only.

b. Company may require Attachment Customer to furnish with any written application for permission to install a Wireless Facilities Attachment a mock-up of the proposed Attachment.

c. Attachment Customer is solely responsible for ensuring that the radiofrequency ("RF") radiation emitted by its Wireless Facilities, alone and/or in combination with any and all sources of RF radiation in the vicinity, is within the limits permitted under all applicable governmental and industry standard safety codes for general population/uncontrolled exposure. Attachment Customer shall install appropriate signage on the poles to which Wireless Facilities have been attached, to warn line workers or the general public of the presence of RF radiation and the need for precautionary measures. Attachment Customer shall periodically inspect the signage and replace the signage if necessary to ensure that the signage, including text and warning symbols, remains clearly visible.

d. Each Wireless Facility installation shall include a switch that operates to disconnect and de-energize the antenna. In non-emergency circumstances, Company employees or contractors will make reasonable efforts to contact Attachment Customer at a telephone number that Attachment Customer has marked on the Wireless Facility installation to request a temporary power shut-down. Company personnel or those of other entities working on the pole will operate the power disconnect switch to ensure that the antenna is not energized while work on the pole is in progress. In emergency circumstances, Company personnel and those of other entities working on Company poles may accomplish the power-down by operation of the power disconnect switch without advance notice to Attachment Customer.

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Attachments on or in any Structure (i) interfere with the use of such Structure or the operation of Company facilities or equipment, (ii) constitute a hazard to the service rendered by Company or any other Persons permitted by Company to use such Structures, (iii) cause a danger to employees of Company or other Persons, or (iv) fail to comply with the Company's standards and applicable requirements of the NESC, NEC, and all other applicable codes, laws and regulations, Attachment Customer shall, within a reasonable period, remove, rearrange, repair or change its Attachments as needed or as directed by Company. In the case of any immediate hazard or danger, such period shall not exceed twenty-four (24) hours from Attachment Customer's receipt of such notice. In case of a hazardous condition or other emergency which requires the immediate remove or relocation of the Attachment Customer's Attachments, the Company may at Attachment Customer's expense, without prior notice and with no liability therefor, remove or relocate such Attachments; provided however, that Company shall notify Attachment Customer of such action as soon as reasonably possible by any appropriate means, including by telephone.

16. REARRANGEMENT; RELOCATION OF STRUCTURES; NEW STRUCTURES

a. If Attachment Customer's Attachments can be accommodated on or in existing Structures only by rearranging Company facilities, or if because of Attachment Customer's proposed Attachments, Company rearranges or transfers its facilities on or in any facility not owned by it, Attachment Customer shall reimburse Company for the actual expense incurred in making such rearrangement or transfer.

b. Upon 45 days prior written notice delivered to Attachment Customer, Company may replace, relocate, or remove any Structure and cause the alteration, relocation or removal of any Attachment, consistent with normal operating, maintenance and development procedures and prudent utility practices. In cases of emergency or dangerous situations, Company shall give only as much prior notice as practical under the circumstances. Company shall bear all costs and expenses of any relocation of the Structures not attributable to or caused by Attachment Customer or its Attachments. Attachment Customer shall bear all costs and expenses of any relocation and removal of the Attachments and all costs and expenses attributable to or caused by Attachment Customer or its Attachments. Attachment Customer shall be solely responsible for any losses occasioned by the interruption of Attachment Customer's business or operations and shall indemnify and hold Company harmless in connection with same.

c. Company may reserve space on its poles in accordance with a bona fide development plan for electric service. Company may direct, by written notice to Attachment Customer, that Attachment Customer's attachments in such reserve space may be removed from

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e. Attachment Customer is solely responsible for ensuring compliance with all Federal Communication Commission antenna registration requirements, Federal Aviation Administration air hazard requirements, or similar requirements with respect to the location of Attachment Customer's Wireless Facilities on Company's poles.

f. Attachment Customer shall not operate its Wireless Facility in a way that causes interference with Company-owned wireless facilities. Attachment Customer shall, after receiving notice from Company of such interference, immediately cease operating its Wireless Facility until it can be operated without causing such interference

g. All power supplies, equipment cabinets, meter bases and other equipment associated with the Wireless Facilities that are large enough to impede accessibility shall be installed off-pole, consistent with the applicable standards of the NESC, Company standards, and all applicable laws, rules, regulations, ordinances, and other applicable governmental directives.

h. Attachment Customer shall not perform any construction, including but not limited to the initial installation of its Wireless Facilities or any maintenance thereof, above the Communications Space without receiving prior approval from Company as to the design, installation, and construction practices, which approval Company shall not unreasonably withhold.

10. OVERLASHING OF CABLE

An Attachment Customer may make an initial overlash of an existing attachment if the overlash is not greater than one-half inch in diameter without any advance notice or application to the Company. No application or advance notice is required for the replacement of an existing cable with a cable that is no greater than one-half inch in diameter. With all other overlashing, Attachment Customer shall provide Company with advance notice to permit Company to visually inspect its Structures to determine the need for a pole loading analysis. For projects involving more than ten (10) spans, the Attachment Customer must provide at least fifteen (15) business days' advance notice. For projects involving ten (10) spans or less, Attachment Customer shall provide at least seven (7) business days' advance notice. Notwithstanding the foregoing, no bundle of Attachment Customer's Cable shall exceed two inches in diameter without Company's express written approval.

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the Structures. Company shall use reasonable efforts to make space available as close in proximity as possible to the former Structures or to offer Attachment Customer the option to perform make-ready work to create additional space on the Structure in question. Attachment Customer shall make such relocation within sixty (60) days of the Company's request.

d. In the event a Person other than Attachment Customer applies to make an Attachment to a Structure on which Attachment Customer has placed an Attachment, and such application requires that Attachment Customer rearrange, transfer or relocate its Attachments, then Attachment Customer shall perform such rearrangement, transfer or relocation within 60 days of notice of such need to rearrange, transfer or relocate. Attachment Customer may condition its rearrangement, transfer or relocation upon reimbursement for the cost of such rearrangement, transfer or relocation. In the event Attachment Customer fails to perform such rearrangement, transfer or relocation within the time frame described above, the affected Attachments may be subject to rearrangement, transfer or relocation by the Person whose application necessitated the rearrangement, transfer or relocation to the extent permitted by law.

17. ABANDONMENT OF ATTACHMENT

Attachment Customer may at any time voluntarily remove its Attachments from any Structure, but shall immediately give Company written notice of such removal on the Company-prescribed form. Attachment Customer shall bear all cost of removal and any costs that Company incurs as a result of such removal and shall pay such costs within 30 days of receipt of an invoice. No refund of any amount paid for use of such Structure will result from Attachment Customer's voluntary removal nor shall such voluntary removal affect any other obligation or liability of Attachment Customer under this Schedule or the Attachment Customer Agreement.

18. INDEMNITIES

Attachment Customer shall protect, defend, indemnify and save harmless Company, its Affiliates, their officers, directors, employees and representatives from and against 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, payment of any settlement or judgment therefor and reasonable attorney's fees that are incurred in such defense, by reason of any claims arising from Attachment Customer's activities under this Schedule, or from Attachment Customer's presence on the Company's premises, or from or in connection with the construction, installation, operation, maintenance, presence, replacement, enlargement, use or removal of any facility of Attachment Customer attached or in the process or being attached to or removed from any Company Structure by Attachment Customer, its employees, agents, or other representatives, including but not

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11. STRAND-MOUNTED WIRELESS COMMUNICATION DEVICES

A strand-mounted wireless communication device shall be considered part of wireline attachment and not subject to permitting or an additional attachment charge if it is located within the one (1) foot vertical space occupied by Attachment Customer's cable and meets all applicable loading, clearance, and RF emission requirements. Before deploying any strand-mounted wireless communications devices other than strand-mounted wi-fi access points, Attachment Customer shall at least sixty (60) days prior to planned deployment notify Company of the proposed deployment and provide sufficient information regarding the nature of device to permit Company to assess the safety and loadbearing implications of the proposed deployment.

12. MAINTENANCE OF ATTACHMENTS AND STRUCTURES

Attachment Customer shall maintain Attachments in safe condition and in good repair, in a manner reasonably suitable to Company and so as not to conflict with any use of Company facilities (including Structures) by Company or any other Person using such facilities pursuant to any license or permit by Company. Attachment Customer shall not interfere with the working use of any other Person's property on or in such facilities or any such property, which may be placed on or near the Structures and other facilities. Company reserves to itself, its successors, Affiliates and assigns, the right to maintain Structures and other Company property and to operate its business and maintain its property in such a manner as will, in its own judgment, best enable it to fulfill its own service requirements. Company shall not be liable to Attachment Customer for any interference with the operation of Attachment Customer's facilities, or loss of business arising in any manner out of the use of Company's Structures or other property.

13. NATIONAL JOINT UTILITIES NOTIFICATION SYSTEM

Within thirty (30) days of executing a Contract, and prior to making application for any Attachment, Attachment Customer will join National Joint Utilities Notification System ("NJUNS"), a web-based system developed to improve joint use communication, and will actively participate during the term of service, by entering field information into the NJUNS system within the times required by the system. Should Attachment Customer fail to actively participate in NJUNS and should such failure cause Company to incur expense or liability to others, Attachment Customer shall reimburse Company its expense and indemnify and hold Company harmless from any damages or liability arising out of such failure. If Company at a later date elects to use a different system for purposes of the communication currently facilitated by NJUNS, Company, shall notify Attachment Customer at least sixty (60) days in advance of such change and Attachment Customer shall make arrangements to participate in that system.

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limited to claims alleging (1) injuries or deaths to Persons; (2) damage to or destruction of property including loss of use thereof; (3) power or communications outage, interruption or degradation; (4) pollution, contamination of or other adverse effects on the environment; (5) violation of governmental laws, regulations or orders; or (6) rearrangement, transfer, or removal of any third party attachment on, from, or to any Company Structure whether suffered directly by Company itself or indirectly by reason of claims, demands or suits against it by third parties, resulting or alleged to have resulted from Attachment Customer's activities under this Schedule, or from Attachment Customer's presence on the Company's premises, or from or in connection with the construction, installation, operation, maintenance, presence, replacement, enlargement, use or removal of any facility of Attachment Customer attached or in the process or being attached to or removed from any Company Structure by Attachment Customer, its employees, agents, or other representatives. The indemnity set forth in this section shall include indemnity for any claims arising out of the joint negligence of Attachment Customer and Company; provided however, the indemnity set forth in this section, but not Attachment Customer's duty to defend, shall be reduced to the extent it is established by final adjudication or mutual agreement of Attachment Customer and Company that the liability to which such indemnity applies was caused by the negligence or willful misconduct of the Company. If Attachment Customer is required under this provision to indemnify Company, Attachment Customer shall have the right to select defense counsel and to direct the defense or settlement of any such claim or suit.

19. UNAUTHORIZED ATTACHMENTS

If Attachment Customer makes any Attachment that requires Company approval under this Schedule and Attachment Customer Agreement and has not obtained such approval, Attachment Customer shall pay a penalty for the Unauthorized Attachment equal to double the current Attachment charge. Attachment Customer shall also submit to Company an application for approval of the Unauthorized Attachment within 30 days of the attachment's discovery. If Attachment Customer fails to submit the required applications or fails to timely remit any necessary payments to Company in connection with the application process (including but not limited to any make-ready fees necessary to accommodate the Unauthorized Attachments), Company may remove any or all such Unauthorized Attachments at Attachment Customer's expense.

20. DEFAULT

If Attachment Customer fails to pay any undisputed fee required, perform any material obligations undertaken or satisfy any warranty or representation made under the Attachment Customer Agreement or with any of the provisions of this Schedule or default in any of its obligations under this Tariff and shall fail within 30 days after written notice from Company to correct such default or non-compliance, Company may, at its option, terminate the license covering the Structures to which such default or non-compliance is applicable; remove,

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14. INSPECTIONS/AUDITS

Company may make periodic inspections for the purpose of determining compliance with this Schedule and with the Contract. Neither Company's right to make inspections nor any inspection made by Company shall relieve an Attachment Customer of any responsibility, obligation or liability assumed under this Schedule.

Upon thirty (30) days' prior notice to Attachment Customer, Company may conduct an audit of its Structures to verify the number, location and type of Attachment Customer's Attachments. Company shall make available to Attachment Customer the report of such audit. Such report shall indicate the location and pole number of all attachments of the Attachment Customer. If the audit reveals that the number of Attachments exceeds the number of Attachments shown in Company's existing records, the excess number of Attachments shall be presumed to be Unauthorized Attachments. Attachment Customer shall have the right to rebut this presumption and demonstrate that the Attachments at issue were authorized. Attachment Customer shall reimburse Company for the expense of such audit, or its pro rata share of such expense if the Attachments of other Attachment Customers are included within the scope of the audit, within thirty (30) days of an invoice for such expenses.

15. INTERFERENCE OR HAZARD

If Company notifies Attachment Customer in writing or orally with written confirmation that the Attachment Customer's Attachments or the condition of Attachment Customer's Attachments on or in any Structure (i) interfere with the use of such Structure or the operation of Company facilities or equipment, (ii) constitute a hazard to the service rendered by Company or any other Persons permitted by Company to use such Structures, (iii) cause a danger to employees of Company or other Persons, or (iv) fail to comply with Company's standards and applicable requirements of the NESC, NEC, and all other applicable codes, laws and regulations, Attachment Customer shall, within a reasonable period, remove, rearrange, repair or change its Attachments as needed or as directed by Company. In the case of any immediate hazard or danger, such period shall not exceed twenty-four (24) hours from Attachment Customer's receipt of such notice. In case of a hazardous condition or other emergency which requires the immediate removal or relocation of the Attachment Customer's Attachments, Company may at Attachment Customer's expense, without prior notice and with no liability therefor, remove or relocate such Attachments; provided however, that Company shall notify Attachment Customer of such action as soon as reasonably possible by any appropriate means, including by telephone.

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relocate or rearrange at Attachment Customer's expense the Attachments to which the default or non-compliance relates; or decline to permit additional Attachments until the failure or default is cured; by giving written notice to Attachment Customer of said termination. In the event of material or repeated default, Company may terminate the Attachment Customer Agreement and recover from Attachment Customer all costs and expenses incurred as a result of reasonably related to the defaults. No refund of any attachment charge will be due on account of such termination.

21. TERMINATION

Attachment Customer may terminate an Attachment Customer Agreement by providing the other written notice of termination at least 60 days prior to the end of the term of service.

Upon termination, Attachment Customer shall remove all Attachments from Structures and other Company property within 180 days. Attachment Customer shall bear all costs of such removal and shall exercise precautions to avoid damage to all Persons and to facilities of Company and other parties in so removing Attachments and assumes all responsibility for all damage it causes. If Attachment Customer's Attachments and other property are not removed within 180 days of termination of this Agreement, unless the time is extended by mutual agreement, Company may remove Attachment Customer's Attachments without liability and Attachment Customer shall pay Company the cost of such removal within 30 days of receipt of an invoice.

Company may terminate an Attachment Customer Agreement without liability to Attachment Customer, upon giving 60 days advance written notice to Attachment Customer that it has a reasonable belief that Company's performance under the Agreement would be illegal under applicable law or regulation or under any order or ruling issued by the PSC, or any other federal, state or local agency having regulatory jurisdiction over Company and same cannot be cured by Company without unreasonable expense or without materially and substantially altering the terms and conditions of the Attachment Customer Agreement; or that termination is required to preserve the Company's rights under any franchise, right-of-way, permit, easement or other similar right which is material and substantial to Company's business or operations. In the event of such termination, the Company and Attachment Customer shall pay and perform obligations that have arisen prior to the effective date of termination, but shall not be obligated to pay and perform obligations, which arise after the effective date of termination.

22. WAIVER

Failure by Company to enforce or insist upon compliance with any of the terms or conditions of this Agreement shall not constitute a general waiver or relinquishment of any such terms or conditions, but the same shall be and remain at all times in full force and effect.

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16. REARRANGEMENT; RELOCATION OF STRUCTURES; NEW STRUCTURES

a. If Attachment Customer's Attachments can be accommodated on or in existing Structures only by rearranging Company facilities, or if because of Attachment Customer's proposed Attachments, Company rearranges or transfers its facilities on or in any facility not owned by it, Attachment Customer shall reimburse Company for the actual expense incurred in making such rearrangement or transfer.

b. Upon forty-five (45) days prior written notice delivered to Attachment Customer, Company may replace, relocate, or remove any Structure and cause the alteration, relocation or removal of any Attachment, consistent with normal operating, maintenance and development procedures and prudent utility practices. In cases of emergency or dangerous situations, Company shall give only as much prior notice as practical under the circumstances. Likewise, in situations where the Company is required to replace, relocate or remove any Structure in less than 45 days by state or local law, easement provisions, contractual obligations to third parties or to meet the Company's obligation to provide electric service to another customer, Company need provide only as much prior notice as reasonably practical under the circumstances, Company shall bear all costs and expenses of any relocation of the Structures not attributable to or caused by Attachment Customer or its Attachments. Attachment Customer shall bear all costs and expenses of any relocation and removal of the Attachments and all costs and expenses attributable to or caused by Attachment Customer or its Attachments. Attachment Customer shall be solely responsible for any losses occasioned by the interruption of Attachment Customer's business or operations and shall indemnify and hold Company harmless in connection with same.

c. Company may reserve space on its poles in accordance with a bona fide development plan for electric service. Company may direct, by written notice to Attachment Customer, that Attachment Customer's attachments in such reserve space may be removed from the Structures. Company shall use reasonable efforts to make space available as close in proximity as possible to the former Structures or to offer Attachment Customer the option to perform make-ready work to create additional space on the Structure in question. Attachment Customer shall make such relocation within sixty (60) days of Company's request.

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23. INSURANCE

a. Throughout the term of service and so long as Attachment Customer's Attachments are on or in Company Structures, Attachment Customer shall provide and maintain the following insurance:

(1) Workers' Compensation and Employer's Liability Policy, which shall include: (a) Workers' Compensation (Coverage A), with statutory limits, and in accordance with the laws of Kentucky; (b) Employer's Liability (Coverage B) with minimum limits of $1,000,000 Bodily Injury by Accident, each Accident, $1,000,000 Bodily Injury by Disease, each Employee; (c) 30 Day Cancellation Endorsement; and (d) Broad Form All States Endorsement.

(2) Commercial General Liability Policy, which shall have minimum limits of $1,000,000 each occurrence; $1,000,000 Products/Completed Operations Aggregate each occurrence; $1,000,000 Personal and Advertising Injury each occurrence, in all cases subject to $2,000,000 in the General Aggregate for all such claims, and including: (a) 30 Day Cancellation Endorsement; (b) Blanket Written Contractual Liability to the extent covered by the policy against liability assumed by Company under the Attachment Customer Agreement; (c) Broad Form Property Damage; and (d) Insurance for liability arising out of blasting, collapse, and underground damage (deletion of X, C, U Exclusions).

(3) Commercial Automobile Liability Insurance covering the use of all owned, non-owned, and hired automobiles, with a bodily injury, including death, and property damage combined single minimum limit of $1,000,000 each occurrence.

(4) Umbrella/Excess Liability Insurance with minimum limits of $2,000,000 per occurrence; $2,000,000 aggregate, to apply to employer's liability, commercial general liability, and automobile liability.

(5) To the extent applicable, if any fixed wing or rotor craft aircraft will be used by Attachment Customer in performing the work, Aircraft Public Liability Insurance covering such aircraft whether owned, non-owned, leased, hired or assigned with a combined single minimum limit for bodily injury and property damage of $5,000,000 including passenger liability coverage.

(6) To the extent applicable, if engineering or other professional services will be separately provided by Attachment Customer as specified in the statements of work, then Professional Liability Insurance with limits of $3,000,000 per occurrence and $3,000,000 in the aggregate, which insurance shall be either on an occurrence basis or on a claims made basis (with a retroactive date satisfactory to Company).

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d. In the event a Person other than Attachment Customer applies to make an Attachment to a Structure on which Attachment Customer has placed an Attachment, and such application requires that Attachment Customer rearrange, transfer or relocate its Attachments, then Attachment Customer shall perform such rearrangement, transfer or relocation within sixty (60) days of notice of such need to rearrange, transfer or relocate. Attachment Customer may condition its rearrangement, transfer or relocation upon reimbursement for the cost of such rearrangement, transfer or relocation. In the event Attachment Customer fails to perform such rearrangement, transfer or relocation within the time frame described above, the affected Attachments may be subject to rearrangement, transfer or relocation by the Person whose application necessitated the rearrangement, transfer or relocation to the extent permitted by law.

17. REMOVAL OF ATTACHMENT

Attachment Customer may at any time voluntarily remove its Attachments from any Structure, but shall immediately give Company written notice of such removal on Company-prescribed form. Attachment Customer shall bear all cost of removal and any costs that Company incurs as a result of such removal and shall pay such costs within thirty (30) days of receipt of an invoice. No refund of any amount paid for use of such Structure will result from Attachment Customer's voluntary removal nor shall such voluntary removal affect any other obligation or liability of Attachment Customer under this Schedule or the Contract.

18. INDEMNITIES

Attachment Customer shall protect, defend, indemnify and save harmless Company, its Affiliates, their officers, directors, employees and representatives from and against 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, payment of any settlement or judgment therefor and reasonable attorney's fees that are incurred in such defense, by reason of any claims arising from Attachment Customer's activities under this Schedule, or the Contract, or from Attachment Customer's presence on Company's premises, or from or in connection with the construction, installation, operation, maintenance, presence, replacement, enlargement, use or removal of any facility of Attachment Customer attached or in the process or being attached to or removed from any Company Structure by Attachment Customer, its employees, agents, or other representatives, including but not limited to claims alleging (1) injuries or deaths to Persons; (2) damage to or destruction of property including loss of use thereof; (3) power or communications outage, interruption or degradation; (4) pollution, contamination of or other adverse effects on the environment; (5) violation of governmental laws, regulations or orders; or (6) rearrangement, transfer, or removal of any third party attachment on, from, or to any Company Structure whether suffered directly by Company itself or indirectly by reason of claims, demands or suits against it by third parties, resulting or alleged to have resulted from Attachment Customer's activities under this Schedule, or the Contract, or from Attachment Customer's presence on

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State Regulation and Rates
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b. Attachment Customer shall require its Contractors and subcontractors to provide and maintain the same insurance coverage as required of Attachment Customer.

c. Except with regard to workers' compensation and professional liability, each policy required under this schedule shall name Company as an additional insured and shall waive rights of subrogation against Company and Company's insurance carrier(s).

d. All policies shall be written by insurance companies that are licensed to do business in Kentucky and that are either satisfactory to Company or have a Best Rating of not less than "A-". These policies shall not be materially changed or canceled except with thirty (30) days written notice to Company from Attachment Customer and the insurance carrier.

e. Company may request a summary of coverage of any of required policies or endorsements; but is not obligated to review any of Attachment Customer's certificates of insurance, insurance policies, or endorsements, or to advise Attachment Customer of any deficiencies in such documents. Company's receipt or review of such documents shall not relieve Attachment Customer from or be deemed a waiver of Attachment Customer's obligations to maintain insurance as provided.

f. Attachment Customer shall submit evidence of such coverage(s) to Company prior to the start of any work under the Attachment Customer Agreement and shall notify Company, prior to the commencement of any work pursuant to any statement of work and/or purchase order, of any threatened, pending and/or paid off claims to third parties, individually or in the aggregate, which otherwise affects the availability of the limits of such coverage(s) inuring to the Company's benefit.

g. Attachment Customer shall provide notice of any accidents or claims involving Attachment Customer's Attachment or Attachment Customer's work under this Schedule and the Attachment Customer Agreement to the Company's designated representative.

h. Attachment Customer may elect not to comply with sections (a) through (f) of this Term 23 if:

(1) Attachment Customer has been in business at least one year and has a corporate credit rating or a senior unsecured rating of at least Baa2 (Moody's) or BBB (Standard & Poor's); or

(2) Attachment Customer has been in business at least one year, and provides its most recent audited financial statements to Company which demonstrates that Attachment Customer meets standards that are at least equivalent to the standards underlying the credit ratings of Baa2 (Moody's) or BBB (Standard and Poor's); or,

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Company's premises, or from or in connection with the construction, installation, operation, maintenance, presence, replacement, enlargement, use or removal of any facility of Attachment Customer attached or in the process or being attached to or removed from any Company Structure by Attachment Customer, its employees, agents, or other representatives. The indemnity set forth in this section shall include indemnity for any claims arising out of the joint negligence of Attachment Customer and Company; provided however, the indemnity set forth in this section, but not Attachment Customer's duty to defend, shall be reduced to the extent it is established by final adjudication or mutual agreement of Attachment Customer and Company that the liability to which such indemnity applies was caused by the negligence or willful misconduct of Company. If Attachment Customer is required under this provision to indemnify Company, Attachment Customer shall have the right to select defense counsel and to direct the defense or settlement of any such claim or suit.

19. UNAUTHORIZED ATTACHMENTS

If Attachment Customer makes any Attachment that requires Company approval or advance notice under this Schedule or the Contract and has not obtained such approval or provided such advance notice, such Attachment shall be deemed an "Unauthorized Attachment," and shall be presumed to have been affixed to Company Structures for two years or since completion of the most recent audit, whichever is occurring earlier. Attachment Customer shall be liable for attachment charges for this time period. In addition to the attachment charges for the period of unauthorized attachment, Attachment Customer shall pay a penalty for each Unauthorized Attachment in the amount of $25.00. Attachment Customer shall also submit to Company an application for approval of the Unauthorized Attachment within thirty (30) days of the attachment's discovery. If Attachment Customer fails to submit the required applications or fails to timely remit any necessary payments to Company in connection with the application process (including but not limited to any make-ready fees necessary to accommodate the Unauthorized Attachments), Company may remove any or all such Unauthorized Attachments at Attachment Customer's expense.

20. DEFAULT

a. If Attachment Customer fails to pay any undisputed fee required, perform any material obligations undertaken or satisfy any warranty or representation made under the Contract comply with any of the provisions of this rate schedule or default in any of its obligations under this Schedule, including Section 5 of the Company's Electric Tariff, and shall fail within thirty (30) days after written notice from Company to correct such default or non-compliance, Company may, at its option, terminate the license covering the Structures to which such default or non-compliance is applicable; remove, relocate or rearrange at Attachment Customer's expense the Attachments to which the default or non-compliance relates; or decline to permit additional Attachments until the failure or default is cured. Company shall give written notice to Attachment Customer of said termination. In the event of material or repeated default, Company may terminate the Contract and recover from Attachment Customer all costs and expenses incurred as a result of related to the defaults. No refund of any attachment charge will be due on account of such termination.

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(3) Attachment Customer's parent company ("Guarantor") meets the criteria set out in (a) or (b) above, and Guarantor provides a written guarantee (in a form acceptable to Company, that the parent company will guarantee all financial obligations associated with Attachment Customer's use of Company's Structures.

24. PERFORMANCE ASSURANCE

a. Attachment Customer shall furnish a surety bond at the following times and in the following amounts and for the following purposes:

(1) During the period of Attachment Customer's initial installation of its wireline pole attachments and at the time of any expansion involving more than 75 poles, a bond in the amount of $2,000 for each 100 poles (or fraction thereof) to which Attachment Customer intends to make a wireline pole attachment;

(2) Upon satisfactory completion of Attachment Customer's initial installation, the amount of bond shall be reduced to $1,000 for each 100 poles (or fraction thereof);

(3) After Attachment Customer has been a customer of Company pursuant to the Attachment Agreement and is not in default under that agreement for a period of three years, the bond shall be reduced to $500 for each 100 poles (or fraction thereof);

(4) If Attachment Customer proposes to attach a Wireless Facility or Facilities to a Structure, Attachment Customer shall post a surety bond in the amount of $1,500 for each pole to which a wireless attachment is attached. The amount of the bond shall not be reduced upon completion of installation or other event.

Each surety bond shall contain the provision that it shall not be terminated prior to six months after Company's receipt of written notice of the desire of the bonding or insurance company to terminate such bond. Company may waive this requirement if an acceptable replacement bond is received before the six months has ended. Upon receipt of such termination notice, Company shall request Attachment Customer to immediately remove its Cables, Wireless Facilities, Attachments and all other facilities from Company Structures. If Attachment Customer should fail to complete the removal of all of its facilities from Company's Structures within 30 days after receipt of such request, then Company may remove Attachment Customer's facilities at Attachment Customer's expense and without liability for any damage to Attachment Customer's facilities. Such bond shall guarantee the payment of any sums which may become due to attachment charges, inspections or work performed by Company under this Schedule or the Attachment Customer Agreement, including the removal of attachments upon termination of the Agreement by any of its provisions.

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21. TERMINATION

Attachment Customer may terminate a Contract by providing Company written notice of termination at least sixty (60) days prior to the end of the term of service.

Upon termination, Attachment Customer shall remove all Attachments from Structures and other Company property within 180 days. Attachment Customer shall bear all costs of such removal and shall exercise precautions to avoid damage to all Persons and to facilities of Company and other parties in so removing Attachments and assumes all responsibility for all damage it causes. If Attachment Customer's Attachments and other property are not removed within 180 days of termination of this Agreement, unless the time is extended by mutual agreement, Company may remove Attachment Customer's Attachments without liability and Attachment Customer shall pay Company the cost of such removal within thirty (30) days of receipt of an invoice.

Company may terminate a Contract without liability to Attachment Customer, upon giving sixty (60) days advance written notice to Attachment Customer that it has a reasonable belief that Company's performance under the Contract would be illegal under applicable law or regulation or under any order or ruling issued by the PSC, or any other federal, state or local agency having regulatory jurisdiction over Company and same cannot be cured by Company without unreasonable expense or without materially and substantially altering the terms and conditions of the Contract; or that termination is required to preserve Company's rights under any franchise, right-of-way, permit, easement or other similar right which is material and substantial to Company's business or operations. In the event of such termination, Company and Attachment Customer shall pay and perform obligations that have arisen prior to the effective date of termination, but shall not be obligated to pay and perform obligations, which arise after the effective date of termination.

22. WAIVER

Failure by Company to enforce or insist upon compliance with any of the terms or conditions of this Schedule or the Contract shall not constitute a general waiver or relinquishment of any such terms or conditions, but the same shall be and remain at all times in full force and effect.

23. INSURANCE

a. Throughout the term of service and so long as Attachment Customer's Attachments are on or in Company Structures, Attachment Customer shall, at its own expense, maintain and carry in full force and effect insurance that meets at least the following requirements (these minimum limits should not be deemed to replace Attachment Customer's full obligation under this Schedule or the Contract):

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Pole and Structure Attachment Charges

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Each surety bond shall be issued by an entity having a minimum corporate debt rating of A- by Standard & Poor's Financial Services LLC at the time of issuance and at all times the relevant bond is outstanding.

b. Attachment Customer may elect not to provide a surety bond if:

(1) Attachment Customer has been in business at least one year and has a corporate credit rating or a senior unsecured rating of at least Baa2 (Moody's) or BBB (Standard & Poor's); or

(2) Attachment Customer has been in business at least one year, and provides its most recent audited financial statements to Company which demonstrates that Attachment Customer meets standards that are at least equivalent to the standards underlying the credit ratings of Baa2 (Moody's) or BBB (Standard and Poor's); or,

(3) Attachment Customer's parent company ("Guarantor") meets the criteria set out in (a) or (b) above, and Guarantor provides a written guarantee (in a form acceptable to Company, that the parent company will guarantee all financial obligations associated with Attachment Customer's use of Company's Structures.

25. CERTIFICATION OF NOTICE REQUIREMENTS
Attachment Customer's highest ranking officer located in Kentucky shall certify under oath on or before January 31 of each year that the Attachment Customer has complied with all notification requirements of this Schedule.

26. NOTICES
Any notice, or request, required by this Schedule or the Attachment Customer Agreement shall be deemed properly given if sent overnight by nationally recognized overnight courier, sent by certified U.S. mail, return receipt requested, postage prepaid, or sent by telecopier with confirmed receipt, to Company's and Attachment Customer's designated representative. The designation of the representative to be notified, his address and/or telecopier number may be changed at any time by similar notice.

27. LIENS
To the extent permitted by law, in the event any construction lien or other encumbrance shall be placed on the Attachments as a result of the actions or omissions of Attachment Customer or its Contractor, Attachment Customer shall promptly, in accordance with applicable laws, discharge such lien or encumbrance without cost or expense to Company. Attachment Customer shall indemnify Company for any and all actual damages that may be suffered or incurred by Company in discharging or releasing said lien or encumbrance.

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(1) Workers' Compensation and Employer's Liability Policy, which shall include: (a) Workers' Compensation (Coverage A); (b) Employer's Liability (Coverage B) with minimum limits of $1,000,000 Bodily Injury by Accident, each Accident, $1,000,000 Bodily Injury by Disease, each Employee; (c) Thirty (30) Day Cancellation Endorsement; and (d) All States Endorsement.

(2) Commercial General Liability Policy, which shall have minimum limits of $1,000,000 each occurrence; $1,000,000 Products/Completed Operations Aggregate each occurrence; $1,000,000 Personal and Advertising Injury each occurrence, in all cases subject to $2,000,000 in the General Aggregate for all such claims, and including: (a) Thirty (30) Day Cancellation Endorsement; (b) Blanket Written Contractual Liability to the extent covered by the policy against liability assumed by Company under the Attachment Customer Agreement; (c) Broad Form Property Damage; (d) General Aggregate Limit – Per Project Endorsement (CG2503); (e) Include Additional Insured Endorsement GC 2010 or CG2037, or its equivalent; and (f) Insurance for liability arising out of blasting, collapse, and underground damage (deletion of X, C, U Exclusions).

(3) Commercial Automobile Liability Insurance covering the use of all owned, non-owned, and hired automobiles, with a bodily injury, including death, and property damage combined single minimum limit of $1,000,000 each occurrence.

(4) Umbrella/Excess Liability Insurance with minimum limits of $5,000,000 per occurrence; $5,000,000 aggregate, to apply to employer's liability, commercial general liability, and commercial automobile liability; including: (a) "Follow Form" provisions; and (b) Note that Total Limits can be met by any combination of primary and umbrella/excess policies.

(5) Aircraft Public Liability - Required at all times when there will be use of any type of fixed wing, rotor, or any type aircraft to perform any work required under this Schedule or the Contract. Aircraft Public Liability Insurance covering such aircraft whether owned, non-owned, leased, hired or assigned with a combined single minimum limit for bodily injury and property damage of $5,000,000 including passenger liability coverage.

(6) Drones – Required at all times if any Unmanned Aircraft Systems (UAS) will be used by Contractor or Subcontractor in performing the work required under this Schedule or the Contract, Drone Liability Insurance covering such aircraft whether owned, non-owned, leased, hired or assigned with a
$1,000,000 per occurrence combined single limit for bodily injury, property damage and personal injury.

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P.S.C. Electric No. 18, Original Sheet No. 40.21

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28. FORCE MAJEURE

In the event Attachment Customer or Company is delayed in or prevented from performing any of its respective obligations under an Attachment Customer Agreement or this Schedule due to acts of God, war, riots, civil insurrection, acts of the public enemy, strikes, lockouts, acts of civil or military authority, government shutdown, fires, floods, earthquakes, fiber, cable or other material failures, shortages or unavailability, delay in delivery not resulting from its failure to timely place orders therefor, lack or delay in transportation, or due to any other causes beyond its reasonable control, then such delay or nonperformance shall be excused.

29. LIMITATION OF LIABILITY

IN NO EVENT SHALL COMPANY OR ANY OF ITS REPRESENTATIVES BE LIABLE UNDER AN ATTACHMENT CUSTOMER AGREEMENT OR THIS SCHEDULE TO ATTACHMENT CUSTOMER FOR CONSEQUENTIAL, INDIRECT, INCIDENTAL, SPECIAL, EXEMPLARY, PUNITIVE OR ENHANCED DAMAGES, LOST PROFITS OR REVENUES OR DIMINUTION IN VALUE, ARISING OUT OF, OR RELATING TO, OR IN CONNECTION WITH AN ATTACHMENT CUSTOMER AGREEMENT OR THIS SCHEDULE, REGARDLESS OF (A) WHETHER SUCH DAMAGES WERE FORESEEABLE, (B) WHETHER OR NOT COMPANY WAS ADVISED OF THE POSSIBILITY OF SUCH DAMAGES AND (C) THE LEGAL OR EQUITABLE THEORY (CONTRACT, TORT OR OTHERWISE) UPON WHICH THE CLAIM IS BASED. THE LIMITATIONS SET FORTH IN THIS SECTION 29 SHALL NOT APPLY TO DAMAGES OR LIABILITY ARISING FROM THE GROSSLY NEGLIGENT ACTS OR OMISSIONS OR WILLFUL MISCONDUCT OF COMPANY IN PERFORMING ITS OBLIGATIONS UNDER AN ATTACHMENT CUSTOMER AGREEMENT OR THIS SCHEDULE.

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(7) Professional Liability - To the extent the work required under this Schedule or the Contract includes any professional services that falls within a professional liability exclusion from the policy provided under Section 23a.(2). Coverage required with limits of Five Million Dollars ($5,000,000) per claim and Five Million Dollars ($5,000,000) in the aggregate, which insurance shall be on a claims made basis. Policy to remain in force continuously for three (3) years or an extended discovery period will be exercised for a period of three (3) years beginning from the time the services under this contract are completed.

b. Attachment Customer shall require its Contractors and subcontractors to provide and maintain the same insurance coverage as required of Attachment Customer.

c. Except with regard to workers' compensation and professional liability, each policy required under this Schedule shall name Company and all its Affiliates as an additional insured and shall waive rights of subrogation against Company, all its Affiliates, and Company's insurance carrier(s). All policies shall be primary and non-contributory. Condition applies to Attachment Customer and its Contractors and Subcontractors.

d. All policies shall be written by insurance companies that are either satisfactory to Company or have an A.M. Best Rating of not less than "A-, VII". These policies shall not be materially changed or canceled except with thirty (30) days written notice to Company from Attachment Customer and the insurance carrier. Attention: Manager, Project Manager – Third Party Attachments, LG&E and KU Services Company, P.O. Box 32020, Louisville, Kentucky 40232.

e. Company may request a summary of coverage of any of the required policies or endorsements; but is not obligated to review any of Attachment Customer's certificates of insurance, insurance policies, or endorsements, or to advise Attachment Customer of any deficiencies in such documents. Company's receipt or review of such documents shall not relieve Attachment Customer from or be deemed a waiver of Attachment Customer's obligations to maintain insurance as provided. Attachment Customer shall provide a summary of coverage within (thirty) 30 days of its request by the Company.

f. Attachment Customer shall provide Certificates of Insurance to Company for each policy of insurance required above and evidence the items noted hereafter: (1) Each Certificate shall properly identify the certificate holder as Company; (2) Under no circumstances shall Attachment Customer begin any work (or allow any Subcontractor to begin any work) prior to submitting Certificate(s) (evidencing the required insurance of Contractor or Subcontractor, as applicable) acceptable to Company. Company retains the right to waive this requirement at its sole discretion; (3) Certificate shall evidence (thirty) 30 days prior notice of cancellation; (4) Certificate shall verify additional insured status on all

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coverage including the endorsements required by Section 23a.(2); (5) Certificate shall verify Blanket Waiver of subrogation - All policies of insurance shall include waivers of subrogation, under subrogation or otherwise, against Company. Except where not applicable by law; (6) Certificate shall verify Primary/Non-contributory wording in favor of Company; and (7) Certificate shall identify policies which are written on a Claims Made coverage form and state the retro date.

g. Attachment Customer shall notify Company, prior to the commencement of any work pursuant to this rate Schedule or the Contract , of any threatened, pending and/or paid off claims to third parties, individually or in the aggregate, which otherwise affects the availability of the limits of such coverage(s) inuring to Company's benefit.

h. Attachment Customer shall provide notice of any accidents, occurences, or claims involving Attachment Customer's Attachment or Attachment Customer's work under this Schedule and the Contract to the LKS Manager, Risk Management at LG&E and KU Services Company, P.O. Box 32030, Louisville, Kentucky 40232.

i. Each policy of insurance required to be maintained by Attachment Customer under this Section 23 (except the Workers' Compensation and Employer's Liability Policy) shall cover all losses and claims of Attachment Customer regardless of whether they arise directly to Attachment Customer or indirectly through Subcontractors (e.g., Attachment Customer's CGL policy must cover Attachment Customer and additional insureds against negligent acts of a Subcontractor, etc.). Section 23 only represents minimum insurance requirements; it does not mitigate or reduce liability required by the indemnity provisions in this Schedule or the Contract. Nor should it be deemed to be the full responsibility of the contractor or subcontractor for liability. Attachment Customer is responsible for their subcontractor's insurance meeting the requirements of Section 23 of this Schedule.

j. Attachment Customer may elect not to comply with sections (a) through (i) of this Section 23 if it provides proof of equivalent levels of self-insurance and:

1. Attachment Customer has been in business at least three (3) years and has a corporate credit rating or a senior unsecured rating of at least Baa2 (Moody's) or BBB (Standard & Poor's); or

2. Attachment Customer has been in business at least three (3) years, and provides its most recent audited financial statements to Company which demonstrates that Attachment Customer meets standards that are at least equivalent to the standards underlying the credit ratings of Baa2 (Moody's) or BBB (Standard and Poor's); or,

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3. A corporate entity affiliated with Attachment Customer ("Guarantor") meets the criteria set out in (1) or (2) above, and Guarantor provides a written guarantee (in a form acceptable to Company, that the corporate affiliate will guarantee all financial obligations associated with Attachment Customer's use of Company's Structures.)

24. PERFORMANCE ASSURANCE

a. Attachment Customer shall furnish Performance Assurance in the following amounts to guarantee the payment of any sums which may become due for attachment charges, inspections, or work performed by the Company under this Schedule or the Contract, including the removal of attachments upon termination of the Contract by any of its provisions:

Number of Attachments	Amount per Attachment	Maximum Total
1-5,000	$20/Attachment	$100,000
5,001-10,000	$10/Attachment	$150,000
10,001+	$5/Attachment	$1,000,000

The above-stated amounts are incremental. By way of example, 7,500 Attachments would require Performance Assurance in the amount of $125,000 ($20 per Attachment for the first 5000 Attachments; $10 per Attachment for the next 2,500 Attachments); 15,000 Attachments would require Performance Assurance in the amount of $175,000 ($20 per Attachment for the first 5000 Attachments; $10 per Attachment the next 5,000 Attachments; and $5 per Attachment for the last 5,000 Attachments).

The amount of the Performance Assurance shall be calculated by the Company annually based on the Attachment Customer's then-existing number of Attachments. Attachment Customer shall provide the Performance Assurance within 30 days of its request by the Company.

If Attachment Customer proposes to attach a Wireless Facility or Facilities to a Structure, Attachment Customer shall post Performance Assurance in the amount of $1,500 for each pole to which a wireless attachment is attached. The amount of the Performance Assurance shall not be reduced upon completion of installation or other event.

In the event the Customer provides Performance Assurance in the form of a surety bond or Letter of Credit, each bond or Letter of Credit shall contain the provision that it shall not be terminated prior to six (6) months after Company's receipt of written notice of the desire of the bonding or insurance company, or bank, to terminate such bond or Letter of Credit. Company may waive this requirement if an acceptable replacement is received before the six (6) months has ended. Upon termination of such surety bond or Letter of

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Credit, , Company shall request Attachment Customer to immediately remove its Cables, Wireless Facilities, Attachments and all other facilities from Company Structures. If Attachment Customer should fail to complete the removal of all of its facilities from Company's Structures within (thirty) 30 days after receipt of such request, then Company may remove Attachment Customer's facilities at Attachment Customer's expense and without liability for any damage to Attachment Customer's facilities.

Each surety bond shall be issued by an entity having a minimum A.M. Best rating of A- and/or Letter of Credit shall be issued by an entity having a minimum Credit Rating of A- by S& P or A3 by Moody's at the time of issuance and at all times the relevant instrument is outstanding.

b. Attachment Customer may elect not to provide Performance Assurance if:

1. Attachment Customer has been in business at least one (1) year and has a corporate credit rating or a senior unsecured rating of at least Baa2 (Moody's) or BBB (S&P's); or

2. Attachment Customer has been in business at least one (1) year, and provides its most recent audited financial statements to Company which demonstrates that Attachment Customer meets standards that are at least equivalent to the standards underlying the credit ratings of Baa2 (Moody's) or BBB (S&P's); or,

3. A corporate affiliate of Attachment Customer ("Guarantor") meets the criteria set out in (1) or (2) above, and Guarantor provides a written guarantee (in a form acceptable to Company, that the corporate affiliate will guarantee all financial obligations associated with Attachment Customer's use of Company's Structures).

Annually, upon the Company's request, an Attachment Customer electing not to provide Performance Assurance under one of the options in c. above shall provide Company with such information as Company requires to determine whether Attachment Customer remains eligible to make such election.

25. CERTIFICATION OF NOTICE REQUIREMENTS

Attachment Customer's highest ranking officer located in Kentucky shall certify under oath on or before January 31 of each year that the Attachment Customer has complied with all notification requirements of this Schedule. The certification shall be in the form prescribed by Company from time to time, and Company shall provide the current version of such form on or after January 1 of each year. If Attachment Customer does not have an officer located in Kentucky, then the certification shall be provided by the officer with responsibility for Attachment Customer's operations in Kentucky.

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26. NOTICES

Any notice, or request, required by this Schedule or the Attachment Customer Agreement shall be deemed properly given if sent overnight by nationally recognized overnight courier, sent by certified U.S. mail, return receipt requested, postage prepaid, or sent by telecopier with confirmed receipt, to Company's and Attachment Customer's designated representative. The designation of the representative to be notified, his address and/or telecopier number may be changed at any time by similar notice.

27. LIENS

To the extent permitted by law, in the event any construction lien or other encumbrance shall be placed on the Attachments as a result of the actions or omissions of Attachment Customer or its Contractor, Attachment Customer shall promptly, in accordance with applicable laws, discharge such lien or encumbrance without cost or expense to Company. Attachment Customer shall indemnify Company for any and all actual damages that may be suffered or incurred by Company in discharging or releasing said lien or encumbrance.

28. FORCE MAJEURE

In the event Attachment Customer or Company is delayed in or prevented from performing any of its respective obligations under an Attachment Customer Agreement or this Schedule due to acts of God, war, riots, civil insurrection, acts of the public enemy, strikes, lockouts, acts of civil or military authority, government shutdown, fires, floods, earthquakes, storms and other major disruptive events, fiber, cable or other material failures, shortages or unavailability, delay in delivery not resulting from its failure to timely place orders therefor, lack or delay in transportation, or due to any other causes beyond its reasonable control, then such delay or nonperformance shall be excused.

29. LIMITATION OF LIABILITY

IN NO EVENT SHALL COMPANY OR ANY OF ITS REPRESENTATIVES BE LIABLE UNDER A CONTRACT OR THIS SCHEDULE TO ATTACHMENT CUSTOMER FOR CONSEQUENTIAL, INDIRECT, INCIDENTAL, SPECIAL, EXEMPLARY, PUNITIVE OR ENHANCED DAMAGES, LOST PROFITS OR REVENUES OR DIMINUTION IN VALUE, ARISING OUT OF, OR RELATING TO, OR IN CONNECTION WITH ACONTRACT OR THIS SCHEDULE, REGARDLESS OF (A) WHETHER SUCH DAMAGES WERE FORESEEABLE, (B) WHETHER OR NOT COMPANY WAS ADVISED OF THE POSSIBILITY OF SUCH DAMAGES AND (C) THE LEGAL OR EQUITABLE THEORY (CONTRACT, TORT OR OTHERWISE) UPON WHICH THE CLAIM IS BASED. THE LIMITATIONS SET FORTH IN THIS SECTION 29 SHALL NOT APPLY TO DAMAGES OR LIABILITY ARISING FROM THE GROSSLY NEGLIGENT ACTS OR OMISSIONS OR WILLFUL MISCONDUCT OF COMPANY IN PERFORMING ITS OBLIGATIONS UNDER AN ATTACHMENT CUSTOMER AGREEMENT OR THIS SCHEDULE.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 41

Standard Rate **EVSE**

Electric Vehicle Supply Equipment

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to customers to be served or currently being served under Company's Standard Rate Schedules GS (with energy usage of 500 kWh or higher per month), AES, PS, TODS, TODP, RTS, and FLS, for the purpose of charging electrical vehicles.

Charging station is offered under the conditions set out hereinafter for electric vehicle supply equipment such as, but not limited to, the charging of electric vehicles via street parking, parking lots, and other outdoor areas.

A basic underground service includes the charging station, existing transformer (or secondary pedestal) and 208/240 volt single-phase service, and necessary conductor and equipment typical of an underground service drop. Said service drop can originate from underground or overhead equipment. Company will furnish, own, install, and maintain the charging unit and cable. Customer will furnish, own and install all duct systems and associated equipment.

Where the location of existing facilities is not suitable, 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.

Company will coordinate charging station installation with the Company's current charging station supplier and the Customer. Customer shall be responsible for the charging equipment installation costs.

Service will be provided under written contract, signed by Customer prior to service commencing.

RATE	Single Charger	Dual Charger	T
Monthly Charging Unit Fee:	$182.31	$306.10	I

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 41

Standard Rate **EVSE**

Electric Vehicle Supply Equipment

APPLICABLE

In all territory served.

AVAILABILITY T

Available to Customers to be served or currently being served under Rates GS (with energy usage of 500 kWh or higher per month), AES, PS, TODS, TODP, RTS, and FLS, for the purpose of charging electric vehicles. T T

Charging station is offered under the conditions set out hereinafter for electric vehicle supply equipment such as, but not limited to, the charging of electric vehicles via street parking, parking lots, and other outdoor areas.

A basic underground service includes the charging station, existing transformer (or secondary pedestal) and 208/240 volt single-phase service, and necessary conductor and equipment typical of an underground service drop. Said service drop can originate from underground or overhead equipment. Company will furnish, own, install, and maintain the charging unit and cable. Customer will furnish, own and install all duct systems and associated equipment.

Where the location of existing facilities is not suitable, 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.

Company will coordinate charging station installation with Company's current charging station supplier and Customer. Customer shall be responsible for the charging equipment installation costs. T T

Service will be provided under written contract, signed by Customer prior to service commencing.

RATE	Single Charger	Dual Charger	
Monthly Charging Unit Fee:	$134.34	$196.64	R/R

DATE OF ISSUE: September 28, 2018

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 41.1
Canceling P.S.C. No. 18, Original Sheet No. 41.1

Standard Rate **EVSE**
Electric Vehicle Supply Equipment

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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
Franchise Fee	Sheet No. 90	
School Tax	Sheet No. 91	

ENERGY CONSUMPTION
Determination of energy applies to the non-metered charging station. The applicable fuel clause charge or credit will be based on an annual 5,852 kilowatt-hours.

PAYMENT
The EVSE charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

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. Cancellation by Customer prior to the expiration of the initial term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the initial term of the contract.

TERMS AND CONDITIONS
1. Service shall be furnished under Company's Terms and Conditions set out in this Tariff Book, except as set out herein.

2. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for installation.

3. 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 and/or equipment is made to Company facilities, Customer must have an attachment agreement with Company.

4. 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.

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 41.1

Standard Rate **EVSE**
Electric Vehicle Supply Equipment

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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Franchise Fee	Sheet No. 90	D
School Tax	Sheet No. 91	

ENERGY CONSUMPTION
Determination of energy applies to the non-metered charging station. The applicable fuel clause charge or credit will be based on an annual 5,852 kilowatt-hours.

PAYMENT
The EVSE charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

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. Cancellation by Customer prior to the expiration of the initial term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the initial term of the contract.

TERMS AND CONDITIONS
1. Service shall be furnished under Company's Terms and Conditions in this Tariff Book, except as set out herein. T

2. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for installation.

3. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and Customer. Where attachment of Customer's devices and/or equipment is made to Company facilities, Customer must have an attachment agreement with Company. T

4. 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.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

Standard Rate **EVSE**
Electric Vehicle Supply Equipment

TERMS AND CONDITIONS (continued) T

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

6. If Customer requests the removal of an existing charging station, including, but not limited to, poles, or other supporting facilities that were in service less than twenty (20) years, and requests installation of replacement facilities within five (5) years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.

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

8. 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.

9. Notwithstanding the provisions of 807 KAR 5:006, Section 14(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 service shall furnish Company with realistic estimates of prospective electricity requirements.

10. Customer shall agree to permit Company to obtain specific charging station usage data directly from the Charging Station Supplier.

MINIMUM CHARGE
The Monthly Charging Unit Fee shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
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2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

Standard Rate **EVSE**
Electric Vehicle Supply Equipment

TERMS AND CONDITIONS (continued)

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

6. If Customer requests the removal of an existing charging station, including, but not limited to, poles, or other supporting facilities that were in service less than twenty (20) years, and requests installation of replacement facilities within five (5) years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.

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

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9. Notwithstanding the provisions of 807 KAR 5:006, Section 14(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 service shall furnish Company with realistic estimates of prospective electricity requirements.

10. Customer shall agree to permit Company to obtain specific charging station usage data directly from the Charging Station Supplier.

MINIMUM CHARGE
The Monthly Charging Unit Fee shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Public Service Commission in Case No.
2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 42
Canceling P.S.C. No. 18, Original Sheet No. 42

Standard Rate **EVC**
Electric Vehicle Charging

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to operators of licensed electric vehicles (EV). EV Customer is defined as the party who owns/operates a licensed electric vehicle, connects that vehicle for the purpose of receiving vehicle charging service to a Company-owned charging station providing service under this schedule, and willingly accepts the Company's fee structure for the vehicle charging service. EVC is offered under the conditions set out hereinafter for the purpose of charging EVs via street parking, parking lots, and other outdoor areas. EV Customers' charging systems must meet applicable charging standards.

Company assumes no liability or responsibility for any potential automotive-related incidents that occur at specific charging locations. EV Customer accepts all restrictions related to the temporary parking space.

RATE
Fee Per Hour: $2.84

Charging Unit Fee includes an Energy Charge and Adjustment Clauses.

Charging sessions of less than a full hour will be prorated.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above includes the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87

The bill amount specified above will be increased or decreased in accordance with the following: T

Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
Franchise Fee	Sheet No. 90	
School Tax	Sheet No. 91	

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 42

Standard Rate **EVC**
Electric Vehicle Charging

APPLICABLE
In all territory served.

AVAILABILITY T
Available to operators of licensed electric vehicles (EV). EV Customer is defined as the party who owns/operates a licensed electric vehicle, connects that vehicle for the purpose of receiving vehicle charging service to a Company-owned charging station providing service under this schedule, and willingly accepts Company's fee structure for the vehicle charging service. EVC is (T) offered under the conditions set out hereinafter for the purpose of charging EVs via street parking, parking lots, and other outdoor areas. EV Customers' charging systems must meet applicable charging standards. Service under this rate schedule is limited to a maximum of ten stations. (N) Company will accept Customers on a first-come-first-served basis (N)

Company assumes no liability or responsibility for any potential automotive-related incidents that occur at specific charging locations. EV Customer accepts all restrictions related to the temporary parking space.

RATE

Fee for First Two (2) Hours:	$0.75 per Hour	T/R
Fee for Every Hour After First Two (2) Hours:	$1.00 per Hour	N/R

Charging Unit Fee includes an Energy Charge, adjustment clauses, and applicable franchise fee and tax. T T

Charging sessions of less than a full hour will be prorated.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above includes the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87

The bill amount specified above will be increased or decreased in accordance with the following: D

Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 42.1

Standard Rate **EVC**
Electric Vehicle Charging

TERMS AND CONDITIONS

1. Service shall be furnished under the following Terms and Conditions and excludes the Company's Terms and Conditions set out in this Tariff Book.

2. EV Customer is required to pay by means of credit card or Charging Station Supplier account.
   a. Credit Card must be chip enabled (if card is not chip enabled, Customer must call the Charging Station Supplier at toll-free number provided at station), or
   b. EV Customer is required to open a Charging Station Supplier account and accepts all terms and conditions of Charging Station Supplier.

3. 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.

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

5. In no event shall Company have any liability to EV Customer, the owner of a vehicle receiving charging service, or any other party affected by the electrical service to EV 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 EV Customer, the owner of a vehicle receiving charging service, or any other party. In the event that EV Customer's use of Company's service causes damage to Company's property or injuries to persons, EV 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.

6. By connecting a vehicle to the Charging Station, the EV Customer represents that the EV Customer is authorized to operate that vehicle and to connect it to the Charging Station for the purpose of receiving vehicle charging service.

7. All service and maintenance will be performed only during regular scheduled working hours of Company.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: April 11, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00355 dated April 11, 2016

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 42.1

Standard Rate **EVC**
Electric Vehicle Charging

TERMS AND CONDITIONS

1. Service shall be furnished under the following Terms and Conditions and excludes Company's Terms and Conditions set out in this Tariff Book. T

2. EV Customer is required to pay by means of credit card or Charging Station Supplier account.
   a. Credit Card must be chip enabled (if card is not chip enabled, Customer must call the Charging Station Supplier at toll-free number provided at station), or
   b. EV Customer is required to open a Charging Station Supplier account and accepts all terms and conditions of Charging Station Supplier.

3. 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.

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

5. In no event shall Company have any liability to EV Customer, the owner of a vehicle receiving charging service, or any other party affected by the electrical service to EV 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 EV Customer, the owner of a vehicle receiving charging service, or any other party. In the event that EV Customer's use of Company's service causes damage to Company's property or injuries to persons, EV 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.

6. By connecting a vehicle to the Charging Station, the EV Customer represents that the EV Customer is authorized to operate that vehicle and to connect it to the Charging Station for the purpose of receiving vehicle charging service.

7. All service and maintenance will be performed only during regular scheduled working hours of Company.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, 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 19, and the results show the meter is within the limits allowed by 807 KAR 5:041, Section 17(1), the customer will be charged $75.00 to cover the test and transportation costs.

DISCONNECT/RECONNECT SERVICE CHARGE

A charge of $28.00 will be made to cover disconnection and reconnection of electric service when discontinued for non-payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, 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 $28.00 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 $15.00 per month per installed set of pulse-generating equipment will be made to those data pulses. Time pulses will not be supplied.

D

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, 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 $3.00 to cover the additional processing costs. R

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 19, and the results show the meter is within the limits allowed by 807 KAR 5:041, Section 17(1), the Customer will be charged $75.00 to cover the test and transportation costs.

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 occurs. No charge will be made for Customers qualifying T for service reconnection pursuant to 807 KAR 5:006, Section 16, 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 $28.00 to cover disconnection and reconnection of electric service, such charge to be made before reconnection occurs. T

METER PULSE CHARGE

Where a Customer desires and Company is willing to provide data meter pulses, a charge of $25.00 I per month per installed set of pulse-generating equipment will be made to those data pulses. Time pulses will not be supplied.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 45.1 N

Standard Rate

Special Charges

UNAUTHORIZED RECONNECT CHARGE

When the Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service:

1. A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;
2. A charge of $90.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter;
3. A charge of $110.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter;
4. A charge of $174.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter System (AMS) meter; or
5. A charge of $177.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 45.1

Standard Rate

Special Charges

UNAUTHORIZED RECONNECT CHARGE

When Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service: T

1. A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;
2. A charge of $90.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter;
3. A charge of $110.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter;
4. A charge of $174.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Advanced Metering System (AMS) meter; or T
5. A charge of $177.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 50

Standard Rate Rider **CSR-1** T

Curtailable Service Rider-1 T

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be limited to customers served under applicable power schedules who contract for not less than 1,000 kVA individually, and executed a contract under this rider prior to July 1, 2017. Company will not enter into contracts for additional curtailable demand, even with customers already participating in this rider, on or after July 1, 2017. 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. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than sixty (60) 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. Company will request physical curtailment only when (1) all available units have been dispatched or are being dispatched and (2) all off-system sales have been or are being curtailed. 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. Customer's choosing to curtail rather than buy through during any of the 275 hours of Company-requested curtailment with a buy-through option each year shall not reduce, diminish, or detract from the 100 hours of physical curtailment Company may request each year. 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 in kVA. 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 kVA demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
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2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 50

Standard Rate Rider **CSR-1**

Curtailable Service Rider-1

APPLICABLE

In all territory served.

AVAILABILITY T

Availability limited to Customers served under applicable rate schedules who contract for not less than 1,000 kVA individually, and executed a contract under this rider prior to July 1, 2017. Company will not enter into contracts for additional curtailable demand, even with Customers already participating in this rider, on or after July 1, 2017. 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 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. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than sixty (60) minutes notice when either requesting or canceling a curtailment. T

Company may request at its sole discretion up to 100 hours of physical curtailment per year. Company will request physical curtailment only when (1) all available units have been dispatched or are being dispatched and (2) all off-system sales have been or are being curtailed. 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. Customers choosing to curtail rather than buy through during any of the 275 hours of Company-requested curtailment with a buy-through option each year shall not reduce, diminish, or detract from the 100 hours of physical curtailment Company may request each year.

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 in kVA. 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 kVA demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance.

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On and After November 1, 2018

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 50.1

Standard Rate Rider **CSR-1** T

Curtailable Service Rider-1 T

Option B -- Customer may contract for a given amount of curtailable load in kVA 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 in kVA 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 in kVA 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:	$3.20 per kVA of Curtailable Billing Demand	T/R
Primary Voltage Service:	$3.31 per kVA of Curtailable Billing Demand	T/R

Non-Compliance Charge: $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.

DATE OF ISSUE: July 7, 2017

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 50.1

Standard Rate Rider **CSR-1**

Curtailable Service Rider-1

Option B -- Customer may contract for a given amount of curtailable load in kVA 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 in kVA 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 in kVA 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) Customer's maximum demand during such T curtailment.

RATE

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

Transmission Voltage Service:	$3.20 per kVA of Curtailable Billing Demand
Primary Voltage Service:	$3.31 per kVA of Curtailable Billing Demand

Non-Compliance Charge: $16.00 per kVA

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. Company and Customer may arrange to have installed, at T Customer's expense, the necessary telecommunication and control equipment to allow Company T 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.

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 50.2

Standard Rate Rider **CSR-1** T
Curtailable Service Rider-1 T

CURTAILABLE BILLING DEMAND

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) the Customer's measured maximum 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.

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 is the Cash Price for "Natural Gas, Henry Hub" as posted in *The Wall Street* T
Journal on-line for the most recent day for which a price is posted that precedes the T
day in which the buy-through occurred. T

CERTIFICATION

Upon commencement of service hereunder, the Customer shall be required to demonstrate or certify to the Company's satisfaction the ability to comply with physical curtailment. On an annual basis, Customer will be required to certify continued capability to reduce its demand pursuant to the amount designated in the contract in the event of a request for curtailment. Failure to demonstrate or certify the capability to reduce demand pursuant to the amount designated in the contract may result in termination of service under this rider.

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.

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

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 50.2

Standard Rate Rider **CSR-1**
Curtailable Service Rider-1

CURTAILABLE BILLING DEMAND

For a Customer electing Option A, Curtailable Billing Demand shall be the difference between (a) Customer's measured maximum demand during the billing period for any billing interval during T
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.

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 is the Cash Price for "Natural Gas, Henry Hub" as posted in *The Wall Street Journal* on-line for the most recent day for which a price is posted that precedes the day in which the buy-through occurred.

CERTIFICATION

Upon commencement of service hereunder, Customer shall be required to demonstrate or certify T
to Company's satisfaction the ability to comply with physical curtailment. On an annual basis, T
Customer will be required to certify continued capability to reduce its demand pursuant to the amount designated in the contract in the event of a request for curtailment. Failure to demonstrate or certify the capability to reduce demand pursuant to the amount designated in the contract may result in termination of service under this rider.

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 Company requests curtailment, upon request by Customer, Company shall provide a good- T
faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by
Company, Customer shall provide to Company a good-faith, non-binding short-term operational T
schedule for their facility.

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

DATE OF ISSUE: September 28, 2018

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Public Service Commission in Case No.
2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 51 N

Standard Rate Rider **CSR-2**

Curtailable Service Rider-2

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be limited to customers served under applicable power schedules who contract for not less than 1,000 kVA individually, and executed a contract under this rider prior to July 1, 2017. Company will not enter into contracts for additional curtailable demand, even with customers already participating in this rider, on or after July 1, 2017.

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. Company may request or cancel a curtailment at any time during any hour of the year.

Company may request at its sole discretion physical curtailment no more than 20 times per calendar year totaling no more than 100 hours. Company will request physical curtailment only when more than 10 of the Companies' primary combustion turbines (CTs) (those with a capacity greater than 100 MW) are being dispatched, irrespective of whether the Companies are making off-system sales. However, to avoid a physical curtailment a CSR customer may buy through a requested curtailment at the Automatic Buy-Through Price. Any buy-through of a physical curtailment request will not count toward the 100-hour limit or 20-curtailment-request limit, but will count toward the 275 hours under the buy-through option discussed below. If all available units have been dispatched or are being dispatched, the Company may request physical curtailment without a buy-through option. After receiving a physical curtailment request from the Company where a buy-through option is available, a CSR customer will have 10 minutes to inform the Company whether the customer elects to buy through or physically curtail. If the customer elects to physically curtail, the customer will have 30 minutes to carry out the required physical curtailment (i.e., a total of 40 minutes from the time the Company requests curtailment to the time the customer must implement the curtailment). If a customer does not respond within 10 minutes of notice of a curtailment request from the Company, the customer will be assumed to have elected to buy through the requested curtailment, subject to any prior written agreement with the customer. After receiving a physical curtailment request from the Company when no buy-through option is available, a CSR customer will have 40 minutes to carry out the required physical curtailment.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 51

Standard Rate Rider **CSR-2**

Curtailable Service Rider-2

APPLICABLE

In all territory served.

AVAILABILITY T

Availability limited to Customers served under applicable rate schedules who contract for not less T than 1,000 kVA individually, and executed a contract under this rider prior to July 1, 2017. Company will not enter into contracts for additional curtailable demand, even with Customers already participating in this rider, on or after July 1, 2017.

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed 375 hours per year nor shall any single T 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. Company may request or cancel a curtailment at any time during any hour of the year.

Company may request at its sole discretion physical curtailment no more than twenty (20) times T per calendar year totaling no more than 100 hours. Company will request physical curtailment only when more than ten (10) of the Companies' primary combustion turbines (CTs) (those with a T capacity greater than 100 MW) are being dispatched, irrespective of whether the Companies are making off-system sales. However, to avoid a physical curtailment a CSR Customer may buy through a requested curtailment at the Automatic Buy-Through Price. Any buy-through of a physical curtailment request will not count toward the 100-hour limit or 20-curtailment-request limit, but will count toward the 275 hours under the buy-through option discussed below. If all available units have been dispatched or are being dispatched, Company may request physical curtailment without T a buy-through option. After receiving a physical curtailment request from Company where a buy- T through option is available, a CSR Customer will have 10 minutes to inform Company whether the Customer elects to buy through or physically curtail. If the Customer elects to physically curtail, the Customer will have 30 minutes to carry out the required physical curtailment (i.e., a total of 40 minutes from the time Company requests curtailment to the time the Customer must implement the curtailment). If a Customer does not respond within 10 minutes of notice of a curtailment request from Company, the Customer will be assumed to have elected to buy through the requested curtailment, subject to any prior written agreement with the Customer. After receiving a physical curtailment request from Company when no buy-through option is available, a CSR Customer will T have 40 minutes to carry out the required physical curtailment.

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 51.1 N

Standard Rate Rider **CSR-2**
Curtailable Service Rider-2

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. Customer's choosing to curtail rather than buy through during any of the 275 hours of Company-requested curtailment with a buy-through option each year shall not reduce, diminish, or detract from the 100 hours of physical curtailment Company may request each year. For such curtailments, Company will give no less than sixty (60) minutes notice when either requesting or canceling a curtailment.

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 in kVA. 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 kVA demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance.

Option B -- Customer may contract for a given amount of curtailable load in kVA 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 in kVA 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 in kVA 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.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 51.1

Standard Rate Rider **CSR-2**
Curtailable Service Rider-2

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. Customers choosing to curtail rather than buy through during any of the 275 hours of Company-requested curtailment with a buy-through option each year shall not reduce, diminish, or detract from the 100 hours of physical curtailment Company may request each year. For such curtailments, Company will give no less than sixty (60) minutes notice when either requesting or canceling a curtailment.

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 in kVA. 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 kVA demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance.

Option B -- Customer may contract for a given amount of curtailable load in kVA 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 in kVA 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 in kVA 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) Customer's maximum demand during such curtailment. T

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On and After November 1, 2018

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Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 51.2 N

Standard Rate Rider **CSR-2**

Curtailable Service Rider-2

RATE

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

Transmission Voltage Service:	$ 5.90 per kVA of Curtailable Billing Demand
Primary Voltage Service:	$ 6.00 per kVA of Curtailable Billing Demand

Non-Compliance Charge: $16.00 per kVA

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 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.

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 is the Cash Price for "Natural Gas, Henry Hub" as posted in *The Wall Street Journal* on-line for the most recent day for which a price is posted that precedes the day in which the buy-through occurred.

DATE OF ISSUE: July 7, 2017

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 51.2

Standard Rate Rider **CSR-2**

Curtailable Service Rider-2

RATE

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

Transmission Voltage Service:	$ 5.90 per kVA of Curtailable Billing Demand
Primary Voltage Service:	$ 6.00 per kVA of Curtailable Billing Demand

Non-Compliance Charge: $16.00 per kVA

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. Company and Customer may arrange to have installed, at T Customer's expense, the necessary telecommunication and control equipment to allow Company T to control Customer's 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) Customer's measured maximum demand during the billing period for any billing interval during T 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.

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 is the Cash Price for "Natural Gas, Henry Hub" as posted in *The Wall Street Journal* on-line for the most recent day for which a price is posted that precedes the day in which the buy-through occurred.

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 51.3 N

Standard Rate Rider **CSR-2**

Curtailable Service Rider-2

CERTIFICATION

Upon commencement of service hereunder, the Customer shall be required to demonstrate or certify to the Company's satisfaction the ability to comply with physical curtailment. On an annual basis, Customer will be required to certify continued capability to reduce its demand pursuant to the amount designated in the contract in the event of a request for curtailment. Failure to demonstrate or certify the capability to reduce demand pursuant to the amount designated in the contract may result in termination of service under this rider.

TERM OF CONTRACT

The minimum original contract period shall be two (2) years 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.

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

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 51.3

Standard Rate Rider **CSR-2**

Curtailable Service Rider-2

CERTIFICATION

Upon commencement of service hereunder, Customer shall be required to demonstrate or certify T
to Company's satisfaction the ability to comply with physical curtailment. On an annual basis, T
Customer will be required to certify continued capability to reduce its demand pursuant to the amount designated in the contract in the event of a request for curtailment. Failure to demonstrate or certify the capability to reduce demand pursuant to the amount designated in the contract may result in termination of service under this rider.

TERM OF CONTRACT

The minimum original contract period shall be two (2) years 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 Company requests curtailment, upon request by Customer, Company shall provide a good- T
faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by T
Company, Customer shall provide to Company a good-faith, non-binding short-term operational T
schedule for their facility.

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 55
Canceling P.S.C. No. 18, Original Sheet No. 55

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE T

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 (on-peak hours)	$0.03229 per kWh	T/R
2. For winter billing months of December, January and February (on-peak hours)	$0.02852 per kWh	T/I
3. During all other hours (off-peak hours)	$0.02666 per kWh	R

On-peak hours for summer billing months of June through September are defined as weekdays (exclusive of holidays) from 8:01 A.M. to 9:00 P.M., Eastern Standard Time (under 1 above). T

On-peak hours for winter billing months of December through February are defined as weekdays (exclusive of holidays) from 6:01 A.M. to 9:00 P.M., Eastern Standard Time (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 $0.02758 per kWh R

DATE OF ISSUE: May 29, 2018

DATE EFFECTIVE: June 29, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 55

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE

In all territory served.

AVAILABILITY T

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 (on-peak hours)	$0.03229 per kWh
2. For winter billing months of December, January and February (on-peak hours)	$0.02852 per kWh
3. During all other hours (off-peak hours)	$0.02666 per kWh

On-peak hours for summer billing months of June through September are defined as weekdays (exclusive of holidays) from 8:01 A.M. to 9:00 P.M., Eastern Standard Time (under 1 above).

On-peak hours for winter billing months of December through February are defined as weekdays (exclusive of holidays) from 6:01 A.M. to 9:00 P.M., Eastern Standard Time (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 $0.02758 per kWh

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Bills Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 55.1
Canceling P.S.C. No. 18, Original Sheet No. 55.1

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

SELECTION OF RATE AND METERING

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

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

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

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

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

PAYMENT

Any payment due from Company to Seller will be due within sixteen (16) business days (no less than twenty-two (22) calendar 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. T

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:

DATE OF ISSUE: May 29, 2018

DATE EFFECTIVE: June 29, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 55.1

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

SELECTION OF RATE AND METERING

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

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

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

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

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

PAYMENT

Any payment due from Company to Seller will be due within sixteen (16) business days (no less than twenty-two (22) calendar 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:

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Bills Rendered
On and After June 29, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 55.2

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,

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: December 5, 1985

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 55.2

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,

DATE OF ISSUE: September 28, 2018

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 55.3

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

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.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: December 5, 1985

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 55.3

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

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.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Bills Rendered
On and After December 5, 1985

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 56

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

AVAILABILITY

In all territory served.

APPLICABILITY OF SERVICE

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

RATES FOR PURCHASES FROM QUALIFYING FACILITIES

Energy Component Payments

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

Capacity Component Payments

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

Determination of CAP_i

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

1. System demand is less than or equal to Company's capacity:
   $D_1 \leq C_{KU}$; $CAP_i = 0$
2. System demand is greater than Company's capacity but less than or equal to the total of Company's capacity and the capacity provided by a QF:

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

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: April 17, 1999

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 56

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE T

In all territory served.

AVAILABILITY T

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

RATES FOR PURCHASES FROM QUALIFYING FACILITIES

Energy Component Payments

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

Capacity Component Payments

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

Determination of CAP_i

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

1. System demand is less than or equal to Company's capacity:
   $D_1 \leq C_{KU}$; $CAP_i = 0$
2. System demand is greater than Company's capacity but less than or equal to the total of Company's capacity and the capacity provided by a QF:

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Bills Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 56.1

Standard Rate Rider **LQF**

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

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

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

PAYMENT

Company shall pay each bill for electric power rendered to it in accordance with the terms of the contract, within sixteen (16) business days (no less than twenty-two (22) calendar 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: July 7, 2017

DATE EFFECTIVE: April 17, 1999

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 56.1

Standard Rate Rider **LQF**

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

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

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

PAYMENT

Company shall pay each bill for electric power rendered to it in accordance with the terms of the contract, within sixteen (16) business days (no less than twenty-two (22) calendar days) of the date the bill is rendered. In lieu of such payment plan, Company will, upon written request, credit Customer's account for such purchases. T

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: September 28, 2018

DATE EFFECTIVE: With Bills Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, 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.

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. A billing period credit is a kWh-denominated electricity credit only, not a monetary credit.

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 billing-period credit for the net delivery on Customer's bill for the succeeding billing periods. If Customer takes service under a time-of-use or time-of-day rate schedule, Company will apply billing-period credits Customer creates in a particular time-of-day or time-of-use block only to offset net energy consumption in the same time-of-day or time-of-use block in future billing periods; such credits will not be used to offset net energy consumption in other time-of-day or time-of-use blocks in any billing period. Any such unused excess billing-period credits will be carried forward and drawn on by Customer as needed. Unused excess billing-period credits existing at the time Customer's service is terminated end with Customer's account and are not transferrable between customers or locations.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 57

Standard Rate Rider **NMS**

Net Metering Service

APPLICABLE

In all territory served.

AVAILABILITY T

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. Standard Rate Rider NMS is intended to comply with all provisions of the Interconnection and Net T Metering Guidelines approved by the Kentucky Public Service Commission, 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.

DEFINITIONS

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

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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 Customer. This provision does not relieve Customer's responsibility to pay metering T costs embedded in Company's Commission-approved base rates. Additional meters, requested T 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 billing-period credit for the net delivery on Customer's bill for the succeeding billing periods. If Customer takes service under a time-of-use or time-of-day rate schedule, Company will apply billing-period credits Customer creates in a particular time-of-day or time-of-use block only to offset net energy consumption in the same time-of-day or time-of-use block; such credits will not be used to offset T net energy consumption in other time-of-day or time-of-use blocks in any billing period. Any such unused excess billing-period credits will be carried forward and drawn on by Customer as needed. Unused excess billing-period credits existing at the time Customer's service is terminated end with Customer's account and are not transferrable between Customers or locations.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 57.1

Standard Rate Rider **NMS**
Net Metering Service

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 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.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 57.1

Standard Rate Rider **NMS**
Net Metering Service

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 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.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 57.2

Standard Rate Rider **NMS**
Net Metering Service

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

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.

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 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.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 57.2

Standard Rate Rider **NMS**
Net Metering Service

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

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, Company will notify Customer, and the time between notification and submission of T 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 Company's technical interconnection T requirements. Those requirements are available on line at www.lge-ku.com and upon request.

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 T to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, Company will notify Customer, and the time between notification and submission of T 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 Company T 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.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 57.3

Standard Rate Rider **NMS**
Net Metering Service

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 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.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 57.3

Standard Rate Rider **NMS**
Net Metering Service

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 Kentucky Public Service Commission;
   d. the rules and regulations of the Kentucky Public Service Commission, as may be revised by time-to-time by the Kentucky Public Service Commission:
   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 Company T
shall be responsible for repair of damage caused to the net metering generator resulting T
solely from the negligence or willful misconduct on the part of Company. T
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 rider. T

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 57.4

Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

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

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 57.4

Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

7. Where required by 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. T

   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 Customer to discontinue operation of the net metering generator T 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 rider, and T 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 Company is unable to immediately isolate or cause T 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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Public Service Commission in Case No.
2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 57.5

Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

of persons or damage to property caused by Customer or Customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating 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.

TERMS AND CONDITIONS

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

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 57.5

Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

of persons or damage to property caused by Customer or Customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating 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 Company has been made and verification that the installation is in compliance T
with this tariff. Upon written notification that an approved generating facility is being
transferred to another person, Customer, or location, Company will verify that the installation T
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, Company will T
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.

TERMS AND CONDITIONS

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 57.6

Standard Rate Rider **NMS**
Net Metering Service

LEVEL 1

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

Submit this Application to:

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

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

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

Customer Name: ______________________ Account Number: ______________

Customer Address: ______________________________________

Customer Phone No.: __________ Customer E-mail Address: ____________________

Project Contact Person: ______________________________________

Phone No.: ____________ E-mail Address (Optional): ____________________

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

____

Energy Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Inverter Manufacturer and Model #: ______________________________

Inverter Power Rating: ______________ Inverter Voltage Rating: ______________

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

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

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

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

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

Expected Start-up Date: ______________________

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: November 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 57.6

Standard Rate Rider **NMS**
Net Metering Service

LEVEL 1

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

Submit this Application to:

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

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

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

Customer Name: ______________________ Account Number: ______________

Customer Address: ______________________________________

Customer Phone No.: __________ Customer E-mail Address: ____________________

Project Contact Person: ______________________________________

Phone No.: ____________ E-mail Address (Optional): ____________________

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

____

Energy Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Inverter Manufacturer and Model #: ______________________________

Inverter Power Rating: ______________ Inverter Voltage Rating: ______________

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

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

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

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

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

Expected Start-up Date: ______________________

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 57.7

Standard Rate Rider **NMS**
Net Metering Service

LEVEL 2

Application for Interconnection and Net Metering

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

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

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

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

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

Customer Name: ______________________ Account Number: ______________

Customer Address: ______________________

Project Contact Person: ______________________

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

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

____

____

____

Total Generating Capacity of Generating Facility: ____

Type of Generator: ____Inverter-Based ____Synchronous ____Induction

Power Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

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

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

Customer Signature: ______________________ Date: ______________

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: November 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00548 dated July 30, 2010 and 2010-00204 dated September 30, 2010

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 57.7

Standard Rate Rider **NMS**
Net Metering Service

LEVEL 2

Application for Interconnection and Net Metering

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

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

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

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

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

Customer Name: ______________________ Account Number: ______________

Customer Address: ______________________

Project Contact Person: ______________________

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

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

____

____

____

Total Generating Capacity of Generating Facility: ____

Type of Generator: ____Inverter-Based ____Synchronous ____Induction

Power Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

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

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

Customer Signature: ______________________ Date: ______________

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 60

Standard Rate Rider **EF**

Excess Facilities

APPLICABILITY

In all territory served.

AVAILABILITY OF SERVICE

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

DEFINITION OF EXCESS FACILITIES

Excess facilities are lines and equipment which are installed in addition to or in substitution for the normal facilities required to render basic electric service and where such facilities are 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.

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.

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	1.24%

(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%

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 60

Standard Rate Rider **EF**

Excess Facilities

APPLICABLE T

In all territory served.

AVAILABILITY T

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.

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.

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	1.20%	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:

Percentage With Contribution-in-Aid of-Construction	0.47%	R

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 60.1

Standard Rate Rider **EF**

Excess Facilities

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: July 7, 2017

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 60.1

Standard Rate Rider **EF**

Excess Facilities

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 61

Standard Rate Rider **RC**

Redundant Capacity

APPLICABLE

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

AVAILABILITY

Available to customers requesting the reservation of capacity on Company's facilities which are shared by other customers when Company has and is willing to reserve such capacity. Such facilities represent a redundant delivery to provide electric service to the Customer's facility in the event that an emergency or unusual occurrence renders the Customer's principal delivery unavailable for providing service. Where Customer desires to split a load between multiple meters on multiple feeds and contract for Redundant Capacity on those feeds, service is contingent on the practicality of metering to measure any transferred load to the redundant feed.

RATE:

Capacity Reservation Charge

Secondary Distribution	$1.04 per kW/kVA per month	R
Primary Distribution	$0.86 per kW/kVA per month	R

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;
(2) 50% of the maximum demand similarly determined for any of the eleven (11) preceding months; or
(3) the contracted capacity reservation.

TERM OF CONTRACT

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

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 61

Standard Rate Rider **RC**

Redundant Capacity

APPLICABLE

In all territory served. T

AVAILABILITY

Available to customers served under Company's rate schedules which include a demand charge T
or a special contract including a demand charge. T

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 T
event that an emergency or unusual occurrence renders Customer's principal delivery T
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.

RATE:

Capacity Reservation Charge

Secondary Distribution	$1.16 per kW/kVA per month	I
Primary Distribution	$0.99 per kW/kVA per month	I

Applicable to the greater of:

1. the highest average load in kW/kVA (as is appropriate for the demand basis of the rate T
schedule on which Customer is billed) recorded at either the principal distribution feed T
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 T
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: September 28, 2018

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 65

Standard Rate Rider **IL**

Intermittent Loads T

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 15(1)(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. 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.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 65

Standard Rate Rider **IL**

Intermittent Loads

APPLICABLE

In all territory served.

AVAILABILITY T

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 Customer exceed T
the limits set forth in the IEEE standards for such characteristics. In addition, if Customer's use of T
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 Customer in accordance with T
807 KAR 5:006, Section 15(1)(b). Such a termination of service shall not be considered a cancellation of the service agreement or relieve Customer of any minimum billing or other guarantees. 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 Customer's expense. T

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 Adjustment Clause and the Minimum Charge under such rate adjusted in accordance with (a) or T
(b) herein.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

Standard Rate Rider **IL**
Intermittent Loads T

RATE (continued)

(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: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

Standard Rate Rider **IL**
Intermittent Loads

RATE (continued)

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: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 66

Standard Rate Rider **TS**

Temporary/Seasonal Service T

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider is available at the option of Company where:

1. Customer's business does not require permanent installation of Company's facilities excluding service provided for construction of permanent delivery points for residences and commercial buildings, and is of such nature to require only seasonal service or temporary service; or
2. the service is over 50 kW, provided for construction purposes, 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
3. Customer has need for temporary intermittent use of Company facilities and Company has facilities it is willing to provide Customer for installation and operational testing of Customer's equipment. T

This service is available for not less than one (1) month (approximately thirty (30) days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes. Where this service is provided under 2 or 3 above, the Company will determine the term of service, which shall not exceed one (1) year.

CONDITIONS

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

1. Customer shall pay Company for all costs of making temporary connections, including cost of installing necessary transformers, meters, poles, wire and any other material, and any cost of material which cannot be salvaged, and the cost of removing such facilities when load has ceased.
2. Customer shall pay regular rate of the applicable electric rate schedule.
3. Where Customer is receiving service under a standard rate and has need for temporary use of Company facilities, Customer will pay for non-salvageable materials outlined in (1) above plus a monthly charge for the salvageable equipment at the Percentage With No Contribution -in-Aid-of-Construction specified on the Excess Facilities Rider, Rate Sheet No. 60.

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DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 66

Standard Rate Rider **TS**

Temporary-to-Permanent and Seasonal Service T

APPLICABLE

In all territory served.

AVAILABILITY T

This rider is available at the option of Company where:

1. Customer's business requires service provided for construction of permanent delivery points for residences and commercial buildings; or N N
2. Customer's business does not require permanent installation of Company's facilities and is of such nature to require only seasonal service or temporary service; or T
3. Customer's service is over 50 kW, provided for construction purposes, 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 T
4. Customer has need for temporary intermittent use of Company facilities and Company has facilities it is willing to provide Customer for installation and operational testing of Customer's equipment. T

This service is available for not less than one (1) month (approximately thirty (30) days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes. Where this service is provided under 3 or 4 above, Company will determine the term of service, which shall not exceed three (3) years. T T

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:

D

1. For Temporary-to-Permanent service which requires service for construction of permanent delivery points for residences and commercial buildings, the Company will provide a temporary electric service upon request by the customer for a non-refundable charge. This charge, which will be subject to an annual review and revision, shall depend on the facilities which must be installed (and removed) by the Company in order to connect service. N

   The standard charge shall be 15% of the estimated installation and removal cost where the facilities to provide service are already in place. It also applies where all of the installed facilities will be utilized, without modification, as part of a future permanent service.

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Lexington, Kentucky

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Temporary-to-Permanent and Seasonal Service Rate Rider (TS) is now contained on two pages instead of one (formerly Temporary/Seasonal Service)

CONDITIONS (continued)

2. For Seasonal Service where facilities are installed for temporary service that will not be utilized as part of a future permanent service, the 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.

Temporary services for underground or overhead installations are to be constructed as specified by Company standards. Customer will furnish and install material and equipment, including mast for service entrance, conductors, meter base, main disconnect, breaker assembly and grounding. Once the temporary service is no longer needed, the Customer must contact the Company for removal.

For such cases where a temporary service is written upon a refundable contract, the customer will be refunded back the deposit paid for the temporary service after three years of continuous service.

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 67

Standard Rate Rider

Kilowatt-Hours Consumed By Lighting Units

APPLICABLE

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

DETERMINATION OF ENERGY CONSUMPTION

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

HOURS USE TABLE

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

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 67

Standard Rate Rider

Kilowatt-Hours Consumed By Lighting Units

APPLICABLE

In all territory served to determine energy consumption applied to Company's non-metered lighting rate schedules. T

DETERMINATION OF ENERGY CONSUMPTION

The applicable Fuel Adjustment 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. T

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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State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Standard Rate Rider **SGE**

Small Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.

b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one (1) MWh of green power.

RATE

Voluntary monthly contributions of any amount in $5.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $5.00 increments (e.g., $5.00, $10.00, $15.00, or more per month). An eligible customer may participate in Company's "Green Energy Program" by making a request to Company's Call Center or through Company's website enrollment form and may withdraw at any time through a request to Company's Call Center. Funds provided by Customer to Company are not refundable.

b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any Customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one (1) year.

c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

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DATE EFFECTIVE: June 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00467 dated February 22, 2010

The Small Green Energy Rider (SGE) and Large Green Energy Rider (LGE) tariff sheets have been eliminated

Kentucky Utilities Company

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.

DEFINITIONS

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

RATE

Voluntary monthly contributions of any amount in $13.00 increments

TERMS AND CONDITIONS

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

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

The Small Green Energy Rider (SGE) and Large Green Energy Rider (LGE) tariff sheets have been eliminated

Green Tariff Rider (GT) is a new tariff, replacing Small Green Energy Rider (SGE) and Large Green Energy Rider (LGE)

N

Green Tariff

APPLICABLE

In all territory served.

AVAILABILITY

Option #1: Renewable Energy Certificates (RECs)

Available as a rider to customers receiving service under Company's standard RS, RTOD, GS, 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.

Participation in this option may be limited by the ability of the Company to procure RECs from Renewable Resources at a price equal to $13 or less per REC. If the total of all kWh under contract under this tariff equals or exceeds the Company's ability to economically procure RECs (more than $13 per REC), the Company may suspend the availability of this tariff to new participants.

Option #2: Business Solar

Available as a rider to customers receiving service under Company's standard GS, PS, TODS, TODP, RTS, or FLS rate schedules. Service under Option #2 requires Company and Customer to enter into a special contract, which must be filed with and approved by the Kentucky Public Service Commission.

Participation in this option will be limited to Customers who wish to have the Company develop, procure, construct, maintain, manage, and own a solar array. The electrical energy produced by the array will be assigned to the Customer.

Option #3: Renewable Power Agreement

Available as a rider to customers to be served under Company's Standard Rate Schedules TODS, TODP, and RTS. Service under the Renewable Power requires Company and Customer to enter into a special contract, which must be filed with and approved by the Kentucky Public Service Commission.

Customers who wish to purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company. In addition this option is limited to:

1. A customer contracting for a minimum monthly billing load of 10 MVA (or MW as is appropriate).
2. Any agreement must be greater than 10 MW nameplate AC, capped at a system cumulative 50 MW name plate AC and for a term that equals the generation purchase agreement for a minimum period of 5 years.
3. Agreement must be for energy delivered to the Company's transmission system.
4. Energy serving this option must be generated from a renewable resource developed on or after the Kentucky Public Service Commission special contract approval date.

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Green Tariff Rider (GT) is a new tariff, replacing Small Green Energy Rider (SGE) and Large Green Energy Rider (LGE)

Green Tariff

N

DEFINITIONS

1. 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. The locations of these sources are limited to Kentucky, Indiana, Tennessee, Ohio, West Virginia, Virginia, Missouri, and Illinois that are certified for the creation of Renewable Energy Credits by definition 2 and 3 below.
2. 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 and attributes of one MWh of green power. RECs may only be purchased from facilities located in Kentucky, Indiana, Tennessee, Ohio, West Virginia, Virginia, Missouri, and Illinois.
3. Eligible RECs are created from renewable facilities verified and approved by the proven renewable asset tracking systems associated with the major regional Independent System Operators (ISO) operators, PJM's Generation Attribute Tracking System (GATS) or MISO's Midwest Renewable Energy Tracking System (MRETS). The legal ownership of every REC so created is recorded and tracked by GATS or MRETS to assure its authenticity and single ownership.

RATE

Option #1: RECs

Customers who wish to support the development of electricity generated by Renewable Resources may contract to purchase each month a specific number of incremental blocks. All RECs purchased to support Option #1 of this tariff shall be retired by the Company on behalf of the customers.

Rate Schedules RS and GS:
Voluntary monthly contributions of any amount in $5.00 increments

Rate Schedules PS, TODS, TODP, RTS, or FLS:
Voluntary monthly contributions of any amount in $13.00 increments

Option #2: Business Solar

Charges and energy credits for this service will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the firm service rates otherwise available to the Customer and the cost of the business solar facility being directly contracted for by the Customer.

Green Tariff Rider (GT) is a new tariff, replacing Small Green Energy Rider (SGE) and Large Green Energy Rider (LGE)

Kentucky Utilities Company

N

RATE - continued

Option #3: Renewable Power Agreement

Charges and energy credits for this service will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the firm service rates otherwise available to the Customer and the cost of the renewable energy resource, including appropriate transmission costs to deliver the energy to the Customer, being directly contracted for by the Customer.

TERM

Option #1: Customers may participate through a one-time purchase or an automatic monthly purchase agreement. Customer may terminate service under this rider by notifying the Company through its Call Center or Business Office. The charges will be removed on the Customer's next bill after their request to terminate.

Option #2: The term will be agreed upon in a separate written bilateral agreement between the Company and the Customer. Contract to be filed with and approved by the Kentucky Public Service Commission.

Option #3: The term will be agreed upon in the separate written bilateral agreement between the Company and the Customer. Contract to be filed with and approved by the Kentucky Public Service Commission.

TERMS AND CONDITIONS

1. Customers participating in Option #1 may contribute as much as they like in the dollar increments outlined above. (RS, GS - $5, $10, $15, $20, etc), (PS, TODS, TODP, RTS, FLS - $13, $26, $39, etc.)
2. An eligible Customer may participate in the Company's "Green Tariff" by making a request to Company's Call Center, Business Office, or through Company's website enrollment form. Funds provided by Customer to Company are not refundable.
3. Customers may not owe any arrearage prior to participating in the "Green Tariff". Any customer failing to pay the amount the customer pledged to contribute in Option #1 may be removed from the "Green Tariff". Any customer removed from or withdrawing Option #1 of the "Green Tariff" will not be allowed to re-apply for one year.
4. Customer will be billed monthly under the "Green Tariff". 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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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 71

Standard Rate Rider **EDR**

Economic Development Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

RATE

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

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

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

TERMS AND CONDITIONS

Brownfield Development

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

Economic Development

c) Service under EDR for Economic Development is available to:
    1) new customers contracting for a minimum monthly billing load of 1,000 kVA; and

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 71

Standard Rate Rider **EDR**

Economic Development Rider

APPLICABLE

In all territory served.

AVAILABILITY T

Available as a rider to Customers to be served or being served under Rates 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 Kentucky Public Service Commission. 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: D

For the twelve (12) consecutive monthly billings and the subsequent four consecutive twelve (12) monthly billing periods thereafter, the Total Demand Charge shall be reduced by 50%, 40%, 30%, 20%, 10% in the order of Customer's choosing at time of contract filing. All subsequent billing shall be at the full charges stated in the applicable rate schedule after this five (5) year period. N N N N N

"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

1. 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).
2. EDR for Brownfield Development is available only to minimum monthly billing loads of 500 kVA or greater where the Customer takes service from existing Company facilities with no material changes. T T

Economic Development

3. Service under EDR for Economic Development is available to:
    a. new Customers contracting for a minimum monthly billing load of 1,000 kVA, and at least a 50% load factor; and T T

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P.S.C. No. 18, Original Sheet No. 71.1

Standard Rate Rider **EDR**
Economic Development Rider

TERMS AND CONDITIONS
Economic Development (continued)

2) existing customers contracting for a minimum monthly billing load of 1,000 kVA above their Existing Base Load, to be determined as follows:
   i. Company and the existing customer will determine Customer's Existing Base Load by calculating a 12-month rolling average of measured demand. T
   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 (KBI), or the Kentucky Industrial Revitalization Act (KIRA), or the Kentucky Jobs Retention Act (KJRA), or other comparable programs approved by the Commonwealth of Kentucky.

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.

<u>General</u>

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.

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Lexington, Kentucky

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P.S.C. No. 19, Original Sheet No. 71.1

Standard Rate Rider **EDR**
Economic Development Rider

TERMS AND CONDITIONS
Economic Development (continued)

b. Existing Customers contracting for a minimum monthly billing load of 1,000 kVA above their Existing Base Load, and at least a 50% load factor to be determined as follows: T
   i. Company and the existing Customer will determine Customer's Existing Base Load by calculating a twelve (12) month rolling average of measured demand. T
   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 Company and the Customer concerning the affected portion of the Customer's Existing Base Load.

4. A Customer desiring service under EDR for Economic Development must submit an application for service that includes:
   a. a description of the new load to be served;
   b. the number of new employees, if any, Customer anticipates employing associated with the new load;
   c. the capital investment Customer anticipates making associated with the EDR load;
   d. a certification that Customer has been qualified by the Commonwealth of Kentucky for benefits under the Kentucky Business Investment Program (KBI), or the Kentucky Industrial Revitalization Act (KIRA), or the Kentucky Jobs Retention Act (KJRA), or other comparable programs approved by the Commonwealth of Kentucky.

5. 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.

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P.S.C. No. 18, Original Sheet No. 71.2

Standard Rate Rider **EDR**
Economic Development Rider

General (continued)

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.
j) In any billing month where Customer's metered load is less than the load required to be eligible for either Brownfield Development or Economic Development, no credit under EDR will be calculated or applied to Customer's billing.

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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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 71.2

Standard Rate Rider **EDR**
Economic Development Rider

N

Economic Re-Development

6. Service under EDR for Economic Re-Development is available to:
   a. Customers locating at vacant commercial or industrial properties in the Company's service territory which have been unoccupied for at least twelve (12) consecutive months. Verification of vacancy will constitute evidence of minimal to no electrical use during the unoccupied timeframe as determined by the company. Development of green space or undeveloped properties or sites are excluded from the Re-Development rider.
   b. EDR for Economic Re-Development is available only to minimum monthly billing loads of 500 kVA or greater where Customer takes service from the existing electrical infrastructure with no material changes and at least a 50% load factor.
   c. A customer desiring service under must submit an application for service that includes:
      i. a description of the new load to be served;
      ii. the number of new employees, if any, Customer anticipates employing associated with the new load; and
      iii. the capital investment Customer anticipates making associated with the EDR load.
   d. Customers relocating their operations from another premise within the Company's service territory and maintaining the same demand load as indicated on the customer's Load Data Sheet are ineligible to participate in this tariff.
   e. Customers relocating their operations from another premise within the Company's service territory and increasing the demand load as indicated on the customer's Load Data Sheet are eligible to participate in this tariff for the increased demand of 500 kVA minimum and at least a 50% load factor.
   f. 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, that amount shall be determined over a fifteen (15) year period and payable at the end of the fifteen (15) year period.

General

7. 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.
8. Customer may request an EDR effective initial billing date that is no later than twelve (12) months after the date on which the Kentucky Public Service Commission approves the customer agreement.
9. 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.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Economic Development Rider (EDR) is now contained on four pages instead of three

Kentucky Utilities Company

Economic Development Rider

N

10. 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 Kentucky Public Service Commission.
11. No credit under EDR will be calculated or applied to Customer's billing in any billing month in which Customer's metered load is less than the load required to be eligible for either Brownfield Development, Economic Development, or Economic Re-Development.
12. EDR is not available to a new customer that results solely from a change in ownership of a previous customer's account. However, if a change in ownership occurs after the previous customer had entered into an EDR special contract, the successor customer may be allowed to fulfil the balance of the EDR special contract.

TERM OF CONTRACT

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

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Kentucky Utilities Company

P.S.C. No. 18, Second Revision of Original Sheet No. 72
Canceling P.S.C. No. 18, First Revision of Original Sheet No. 72

Standard Rate Rider **SSP**

Solar Share Program Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This optional, voluntary service is available to Company's customers taking service under any Standard Rate Schedule except those served under Retail Transmission Service, Fluctuating Load Service, Lighting Service, Restricted Lighting Service, Lighting Energy Service, Traffic Energy Service, Pole and Structure Attachment Charges, Electric Vehicle Supply Equipment, and Electric Vehicle Charging Service rate schedules. The terms and conditions set out herein are available for and applicable to participation in Company's Solar Share Program.

RATE:

Monthly Charge D

Solar Capacity Charge $6.27 per quarter-kW subscribed I

Monthly Credits and Adjustments

	Rate Schedule	Credit per kWh
Solar Energy Credit (per kWh of pro rata energy produced by the Solar Share Facilities; number of kWh eligible for credit limited to customer's net kWh consumption on each bill)	RS	$0.03237
	RTOD-Energy	$0.03237
	RTOD-Demand	$0.03237
	VFD	$0.03237
	GS	$0.03241
	AES	$0.03243
	PS Secondary	$0.03270
	PS Primary	$0.03171
	TODS	$0.03229
	TODP	$0.03136

Solar FAC Adjustment — Subscriber's billing under Adjustment Clause FAC will be adjusted corresponding to number of kWh to which Solar Energy Credit applies

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On and After September 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 72

Standard Rate Rider **SSP**

Solar Share Program Rider

APPLICABLE

In all territory served.

AVAILABILITY T

This optional, voluntary service is available to Customers taking service under Rates RS, RTOD- T
Energy, RTOD-Demand, VFD, GS, AES, PS, TODS, and TODP. The terms and conditions set T
out herein are available for and applicable to participation in Company's Solar Share Program.

RATE:

A customer may subscribe to capacity in the Solar Share Facilities by paying a One-Time Solar Capacity Charge or a Monthly Solar Capacity Charge—but not both—for each quarter-kW increment subscribed. The customer need not subscribe to all desired capacity using only one subscription approach, but the customer will pay only one kind of charge for each increment of capacity subscribed. For example, a customer subscribing to two quarter-kW increments may pay the One-Time Solar Capacity Charge for one increment and the Monthly Solar Capacity Charge for the other increment. N

One-Time Solar Capacity Charge

A customer subscribing to capacity by paying the One-Time Solar Capacity Charge will receive Solar Energy Credit values subject to the terms and conditions of this Rider for a period of 25 years beginning with and including the first full billing period immediately following the customer's payment in full of the Capacity Charge.

The One-Time Solar Capacity Charge is only available for subscription on Solar Share Facilities that have not begun construction. Any one-time solar capacity subscription that becomes unsubscribed will be made available for subscription under the Monthly Solar Capacity Charge.

One-Time Solar Capacity Charge $790.00 per quarter-kW subscribed N

Monthly Solar Capacity Charge T

Solar Capacity Charge $5.68 per quarter-kW subscribed R
D

Solar Energy Credit N

Each billing period during which the Subscriber has paid in full for subscribed capacity under either N
option above, Company will compare a subscribing customer's pro rata AC energy produced by N
the Solar Share Facilities (truncated to a whole kWh value) to the subscribing customer's energy N
consumption (in kWh) every 15 minutes. If consumption exceeded production, Company will bill N
Customer for the net energy consumed in accordance with Customer's standard rate schedule. N
If production equaled or exceeded consumption in any relevant period, Company will bill N
Customer for zero energy consumption for that period and provide a bill credit for each kWh of N
net production, if any, at the then-applicable non-time-differentiated rate for Company's Standard N
Rate Rider SQF, (Small Capacity Cogeneration and Small Power Production Qualifying N
Facilities) Original Sheet No. 55. N

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 72.1
Canceling P.S.C. No. 18, Original Sheet No. 72.1

Standard Rate Rider **SSP**
Solar Share Program Rider

PROGRAM DESCRIPTION

The Solar Share Program is an optional, voluntary program that allows customers to subscribe capacity in the Solar Share Facilities. Each Solar Share Facility will have an approximate direct-current (DC) capacity of 500 kW and will be available for subscription in nominal 250 W (quarter-kW) DC increments. Each subscribing customer ("Subscriber") may subscribe capacity up to an aggregate amount of 500 kW DC, though no Subscriber may subscribe more than 250 kW DC in any single Solar Share Facility. D

Subscriber's desired capacity will be considered subscribed upon Subscriber's commitment to pay charges under this Rider for at least 12 billing periods (or enters in a contract as required herein for subscriptions of 50 kW DC or more). Subscriber will pay the monthly Solar Capacity Charge for each quarter-kW subscribed beginning with the first billing period in which the subscribed capacity has been in service for the entire billing period. For each such billing period, Subscriber will also receive (i) a bill credit in the amount of the monthly Solar Energy Credit (see Rate above) times the pro rata amount of energy production attributable to Subscriber's subscribed capacity (limited by Subscriber's net kWh consumption for the period being billed) and (ii) a bill adjustment to the Subscriber's Fuel Adjustment Clause (FAC) credits or charges corresponding to the number of kWh for which the Subscriber receives a Solar Energy Credit. N N N/D

Customers subscribing less than 50 kW DC will not be required to enter into a contract concerning their subscriptions; however, a customer may not reduce or cancel a subscription earlier than 12 months from the date of the customer's most recent change to the customer's subscription level following the first billing period for which Subscriber pays Solar Capacity Charges. Therefore, a customer subscribing less than 50 kW has a 12-month payment commitment, and may have a longer commitment if the customer subsequently increases subscribed capacity (which a customer may do at any time) or if the customer chooses to decrease but not cancel the subscription after the initial 12 months. As addressed in Term of Contract below, customers subscribing 50 kW DC or more must enter into a 5-year contract with Company. N T/D D

TERMS AND CONDITIONS

1) Subscriptions will be available on a first-come first-served basis, except that 25% of the capacity of Solar Share Facility No. 1 will be available only to residential customers for the first 45 days of the initial subscription period for new facility. Otherwise, all capacity in the Solar Share Facilities will be available for subscription by all customers on a first-come, first-served basis.

2) Individual subscriptions will be available in nominal 250 W DC (quarter-kW) increments.

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 72.1

Standard Rate Rider **SSP** N
Solar Share Program Rider

PROGRAM DESCRIPTION

The Solar Share Program is an optional, voluntary program that allows customers to subscribe to capacity in the Solar Share Facilities. Each Solar Share Facility will have an approximate direct-current (DC) capacity of 500 kW and will be available for subscription in nominal 250 W (quarter-kW) DC increments. Each subscribing customer ("Subscriber") may subscribe capacity up to an aggregate amount of 500 kW DC, though no Subscriber may subscribe more than 250 kW DC in any single Solar Share Facility.

There are two mutually exclusive options for subscribing to each increment of capacity.

Option 1: Capacity Subscribed by Paying Only the One-Time Solar Capacity Charge

For capacity subscribed by paying the One-Time Solar Capacity Charge, the One-Time Solar Capacity Charge will be included on the Subscriber's bill for the first billing period in which the subscribed capacity achieves commercial operation.

A customer choosing to pay the One-Time Solar Capacity Charge may transfer subscribed capacity between the customer's own accounts or may assign subscribed capacity to another customer. Once assigned, the assigning customer forfeits all rights to the assigned capacity.

A customer who ceases taking service from Company will have 60 calendar days to assign subscribed capacity to another customer within Company's service area. Any capacity such a customer does not assign within 60 days of ceasing to take service will be forfeited and made available to other customers under Option 2: Capacity Subscribed by Paying Only the Monthly Solar Capacity Charge.

Option 2: Capacity Subscribed by Paying Only the Monthly Solar Capacity Charge

For capacity subscribed by paying the Monthly Solar Capacity Charge, the Solar Capacity Charge will be included on the Subscriber's bill beginning with the bill for the first billing period in which the subscribed capacity achieves commercial operation.

Monthly subscriptions of less than 50 kW DC will not require a contract; however, a customer may not reduce or cancel a monthly subscription earlier than 12 months from the date of the customer's most recent change to the customer's monthly subscription level. Therefore, a customer subscribing monthly less than 50 kW has a 12-month commitment from the date of the customer's initial monthly subscription or initial solar facility commercial operation, whichever is later, and may have a longer commitment if the customer subsequently increases monthly subscribed capacity (which a customer may do at any time) or if the customer chooses to decrease but not cancel the monthly subscription after the initial 12 months. Monthly subscriptions of 50 kW DC or more require a 5-year contract with Company.

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 72.2
Canceling P.S.C. No. 18, Original Sheet No. 72.2

Standard Rate Rider **SSP**
Solar Share Program Rider

TERMS AND CONDITIONS (continued)

3) Customer may subscribe as much solar capacity as desired up to an aggregate amount of 500 kW DC. No customer may subscribe more than 250 kW DC in any single Solar Share Facility.

4) Subject to the restrictions above, Company will fill subscriptions as capacity in the Solar Share Facilities becomes available, and will fill subscriptions in the chronological order in which the subscriptions were made. A Subscriber whose subscription the Company can fulfill only partially may either accept the available capacity and await additional capacity, or decline the partial fulfillment, allowing the next awaiting Subscriber(s) to accept the available capacity. Accepting or declining available capacity will not affect a Subscriber's place in the queue of Subscribers awaiting capacity. T/D

5) Customers may not owe any arrearage prior to participating in the Solar Share Program. T

6) Subscribers' pro-rata share of the electricity produced by the Solar Share Facilities will be determined on a billing cycle basis. The corresponding Solar Energy Credit (per kWh) and Solar FAC Adjustment will appear on the Subscriber's bill. T

7) Subscriber may continue to participate in the Program if Subscriber changes premises within the combined Kentucky certified electric service territories of Louisville Gas and Electric Company and Kentucky Utilities Company. T/D D

8) Subscribers whose customer accounts are closed for any reason will not be able to remain in the Program. Upon account closing, Subscriber will be obligated to pay Solar Capacity Charges for any remaining commitment period(s) associated with Subscriber's capacity, e.g., a Subscriber closing an account after having paid only six billing periods' Solar Capacity Charges for less than 50 kW DC subscribed capacity would be obligated to pay the remaining six billing periods' Solar Capacity Charges at the time of account closing. T N N N N N/D

9) Unless constrained by contract (see Term of Contract below), Subscriber may decrease or terminate a subscription any time after 12 months following the date of the most recent change to Subscriber's subscription that occurs after the first billing period for which Subscriber pays Solar Capacity Charges. T N N/D

10) Unless constrained by contract (see Term of Contract below), Subscriber may also increase subscribed capacity at any time. T D

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State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 72.2

Standard Rate Rider **SSP**
Solar Share Program Rider

N

TERMS AND CONDITIONS

1. Individual subscriptions are available in nominal 250 W DC (quarter-kW) increments.

2. Customer may subscribe as much solar capacity as desired up to an aggregate amount of 500 kW DC (nominal). No customer may subscribe more than 250 kW DC (nominal) in any single Solar Share Facility.

3. All One-Time Solar Capacity Charges are non-refundable.

4. Subject to the restrictions above, Company will fill subscriptions as capacity in the Solar Share Facilities becomes available, and will fill subscriptions in the chronological order in which the subscriptions were made. A Subscriber whose subscription the Company can fulfill only partially may either accept the available capacity and await additional capacity, or decline the partial fulfillment, allowing the next awaiting Subscriber(s) to accept the available capacity. Accepting or declining available capacity will not affect a Subscriber's place in the queue of Subscribers awaiting capacity.

5. Customers may not owe any arrearage prior to participating in the Solar Share Program.

6. Subscribers' pro-rata share of the AC electricity produced by the Solar Share Facilities will be determined on a billing-cycle basis. The corresponding Solar Energy Credit will be calculated and appear on the Subscriber's bill.

7. Unless constrained by contract (see Term of Contract below), Subscriber may decrease or terminate a monthly subscription any time after 12 months following the date of the most recent change to Subscriber's monthly subscription capacity at any time.

8. Unless constrained by contract (see Term of Contract below) or condition #2 above, Subscriber may also increase monthly subscribed capacity at any time.

9. Subscriptions made by paying the One-Time Solar Capacity Charge may be transferred between a Subscriber's accounts no more than once per billing period (Solar Energy Credit values do not transfer between accounts or customers). A subscription transfer between a Subscriber's accounts takes effect in the billing period following the billing period in which the Subscriber requests the transfer. A Subscriber may transfer a subscription at any time prior to or including 60 calendar days after the Subscriber terminated service on the account to which the subscription attached. If the Subscriber whose account has been terminated does not transfer the subscription within 60 calendar days, the Subscriber forfeits the subscription.

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 72.3
Canceling P.S.C. No. 18, Original Sheet No. 72.3

Standard Rate Rider **SSP**
Solar Share Program Rider

TERMS AND CONDITIONS (continued)

11) Each subscription under the Solar Share Program applies to a particular meter. Subscribers with multiple meters may obtain multiple subscriptions, one per meter. But Company will not aggregate usage across multiple meters for applying credits, charges, or adjustments under Rider SSP; credits, charges, and adjustments under Rider SSP apply only to the meter associated with the subscription. The only exception to this restriction is if Subscriber has more than one meter for a single service, which multiple meters Company installed for its own operating convenience and bills on an aggregated basis in accordance with Company's Terms and Conditions. T

12) Subscriptions are not transferrable or assignable between customers or between a single customer's meters. T

13) Subscriber's Solar Energy Credit and corresponding Solar FAC Adjustment will apply each billing cycle to the Subscriber's pro rata amount of AC energy produced by the Solar Share Facilities (truncated to a whole kWh value) or Subscriber's net energy consumption (kWh) for the billing period, whichever is less. T

14) For all customers taking service under both of Riders NMS and SSP, Company will apply all provisions of Rider NMS to their bills before applying charges and credits under Rider SSP, including applying the Solar Energy Credit and Solar FAC Adjustment to such customers' net energy consumption. Therefore, customers should note that in months in which a customer taking service under Riders SSP and NMS has net zero energy consumption or net energy production under the terms of Rider NMS—including carryover net-energy credits from previous months, if any—the customer will receive zero Solar Energy Credit and Solar FAC Adjustment under Rider SSP. These provisions apply regardless of whether a customer first took service under Rider NMS before taking service under Rider SSP or vice versa, or if a customer began taking service under both riders simultaneously. T

15) All Renewable Energy Credits ("RECs") related to energy produced by subscribed portions of the Solar Share Facilities will be retired. T

16) Use of any images of the Solar Share Facilities or use any other of Company's intellectual property requires Company licensing prior to use. T

17) Service will be furnished under Company's Terms and Conditions except as provided herein. T

TERM OF CONTRACT

Subscriptions of 50 kW DC or more will require a five (5) year non-transferrable, non-assignable contract between Subscriber and Company.

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State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 72.3

Standard Rate Rider **SSP**
Solar Share Program Rider

N

TERMS AND CONDITIONS (continued)

10. Capacity subscribed by paying the Monthly Solar Capacity Charge is not transferrable or assignable between customers.

11. Capacity subscribed by paying the One-Time Solar Capacity Charge may be assigned between customers, but only within the same Company service territory, at any time prior to or including 60 calendar days after the assigning Subscriber terminated service on the account to which the subscription attached. Once assigned, the assigning customer loses all rights regarding future credits and the ability to subsequently assign the capacity; those rights become the rights of the assignee upon assignment. Assigned capacity cannot be reassigned by the assignee to any other Customer, including the Customer who originally subscribed the assigned capacity. For all purposes other than the Solar Energy Credit, all capacity assignments become effective immediately upon assignment. For the purpose of the Solar Energy Credit, the assignor will receive Solar Energy Credits for the entire billing period in which the assignment occurs; the assignee will receive Solar Energy Credits beginning in the first billing period following the assignment.

12. Unused Solar Energy Credit value is not transferrable between customers or customer accounts. Therefore, a Subscriber's closing a customer account terminates any unused Solar Energy Credit value associated with that account.

13. Participants in SSP are required to have an advanced meter capable of collecting and communicating at least 15 minute interval data.

14. All Renewable Energy Credits ("RECs") related to energy produced by subscribed portions of the Solar Share Facilities will be retired.

15. Use of any images of the Solar Share Facilities or use any other of Company's intellectual property requires Company licensing prior to use.

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

TERM OF CONTRACT

Subscriptions of 50 kW DC or more will require a five (5) year non-transferrable, non-assignable contract between Subscriber and Company.

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Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 75

Standard Rate Rider **EVSE-R**

Electric Vehicle Supply Equipment

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available as a rider to customers to be served or currently being served under Company's Standard Rate Schedules, GS (with energy usage of 500 kWh or higher per month), AES, PS, TODS, TODP, RTS, and FLS for the purpose of charging electrical vehicles, whereby the Customer installs and owns facilities on its side of the point of delivery of the energy supplied hereunder necessary to serve Company-provided charging station.

Charging station under this rider is offered under the conditions set out hereinafter for electric vehicle supply equipment such as, but not limited to, the charging of electric vehicles via street parking, parking lots, and other outdoor areas. Customer is responsible for providing the appropriate voltage levels and connections necessary to operate Company-provided charger.

Company will coordinate charging station installation with the Company's current charging station supplier and the Customer. Customer shall be responsible for the charging equipment installation costs.

Service will be provided under written contract, signed by customer prior to service commencing.

RATE	Single Charger	Dual Charger	T
Monthly Charging Unit Fee:	$131.41	$204.31	R

ADJUSTMENT CLAUSES

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

Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

PAYMENT

The EVSE-R charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 75

Standard Rate Rider **EVSE-R**

Electric Vehicle Supply Equipment

APPLICABLE

In all territory served.

AVAILABILITY T

Available as a rider to Customers to be served or currently being served under Rates GS (with T
energy usage of 500 kWh or higher per month), AES, PS, TODS, TODP, RTS, and FLS for the purpose of charging electrical vehicles, whereby Customer installs and owns facilities on its side T
of the point of delivery of the energy supplied hereunder necessary to serve Company-provided charging station.

Charging station under this rider is offered under the conditions set out hereinafter for electric vehicle supply equipment such as, but not limited to, the charging of electric vehicles via street parking, parking lots, and other outdoor areas. Customer is responsible for providing the appropriate voltage levels and connections necessary to operate Company-provided charger.

Company will coordinate charging station installation with Company's current charging station T
supplier and Customer. Customer shall be responsible for the charging equipment installation T
costs.

Service will be provided under written contract, signed by Customer prior to service commencing.

RATE	Single Charger	Dual Charger	
Monthly Charging Unit Fee:	$123.99	$175.95	R/R

ADJUSTMENT CLAUSES

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

Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

PAYMENT

The EVSE-R charges shall be incorporated with the bill for electric service and will be subject to the same payment provisions.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 75.1

Standard Rate Rider **EVSE-R**
Electric Vehicle Supply Equipment

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. Cancellation by Customer prior to the expiration of the initial term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the initial term of the contract.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions set out in this Tariff Book, except as set out herein.
2. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for installation.
3. 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 and/or equipment is made to Company facilities, Customer must have an attachment agreement with Company.
4. 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.
5. Customer shall be responsible for the cost of charging station replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal wear and tear. Company may decline to provide or to continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.
6. If Customer requests the removal of an existing charging station, including, but not limited to, poles, or other supporting facilities that were in service less than twenty years, and requests installation of replacement facilities within 5 years of removal, Customer agrees to pay to Company its cost of labor to install the replacement facilities.
7. Temporary suspension of charging station is not permitted. Upon permanent discontinuance of service, charging station and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: April 11, 2016

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2015-00355 dated April 11, 2016

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 75.1

Standard Rate Rider **EVSE-R**
Electric Vehicle Supply Equipment

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. Cancellation by Customer prior to the expiration of the initial term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the initial term of the contract.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions set out in this Tariff Book, except as set out herein.
2. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for installation.
3. 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 and/or equipment is made to Company facilities, Customer must have an attachment agreement with Company.
4. 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.
5. Customer shall be responsible for the cost of charging station replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal wear and tear. Company may decline to provide or to continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.
6. If Customer requests the removal of an existing charging station, including, but not limited to, poles, or other supporting facilities that were in service less than twenty (20) years, and requests T
installation of replacement facilities within five (5) years of removal, Customer agrees to pay to T
Company its cost of labor to install the replacement facilities.
7. Temporary suspension of charging station is not permitted. Upon permanent discontinuance of service, charging station and other supporting facilities solely associated with providing service under this tariff, except underground facilities and pedestals, will be removed.

DATE OF ISSUE: September 28, 2018

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State Regulation and Rates
Lexington, Kentucky

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8. 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.
9. Notwithstanding the provisions of 807 KAR 5:006, Section 14(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 service shall furnish Company with realistic estimates of prospective electricity requirements.
10. Customer shall agree to permit Company to obtain specific charging station usage data directly from the Charging Station Supplier.

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

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

8. 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.
9. Notwithstanding the provisions of 807 KAR 5:006, Section 14(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 service shall furnish Company with realistic estimates of prospective electricity requirements.
10. Customer shall agree to permit Company to obtain specific charging station usage data directly from the Charging Station Supplier.

MINIMUM CHARGE
As determined by this rider and the rate schedule to which it is attached.

DUE DATE OF BILL
Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

SCHOOL POWER SERVICE

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rate schedule is available as an option for secondary service P-12 schools whose 12-month-average monthly minimum secondary loads exceed 50 kW and whose 12-month-average monthly maximum loads do not exceed 250 kW.

Service under this rate schedule is limited until the total projected revenue impact for customers taking service under SPS and STOD combined is $750,000 annually compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served; wherein such projected impacts shall be calculated on billing data for the most recent 12-month period available to the Companies. The Kentucky School Boards Association ("KSBA") will be responsible for proposing schools for participation in this optional rate and the order in which such schools are proposed. KU will calculate and provide to KSBA the projected revenue impact of each proposed school.

A customer electing to take service under this rate schedule who subsequently elects to take service under another rate schedule, may not be allowed to return to this optional rate for 12 months from the date of exiting this rate schedule.

This rate schedule will expire on July 1, 2020 or when KU files it next base rate case, whichever is earlier. Customers on this rate schedule will be transferred at that time to the rate schedule under which they were formerly served.

RATE	Secondary	
Basic Service Charge per month:	$90.00	
Plus an Energy Charge per kWh:	$ 0.03289	
Plus a Demand Charge per kW:		
Summer Rate:		
(Five Billing Periods of May through September)	$18.75	I
Winter Rate:		
(All other months)	$16.78	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, or
b) a minimum of 50% of the highest measured load in the preceding eleven (11) monthly billing periods, or
c) if applicable, a minimum of 60% of the contract capacity based on the maximum expected load on the system or on facilities specified by Customer.

DATE OF ISSUE: January 8, 2018

DATE EFFECTIVE: January 30, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2017-00266 dated December 19, 2017

School Power Service Pilot Program (SPS) and School Time-of-Day Service Pilot Program (STOD) are being eliminated

Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 79.1
Canceling P.S.C. No. 18, Original Sheet No. 79.1

Standard Rate **SPS**
SCHOOL POWER 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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
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 month.

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

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

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

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month’s charges.

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

School Power Service Pilot Program (SPS) and School Time-of-Day Service Pilot Program (STOD) are being eliminated

SCHOOL TIME-OF-DAY SERVICE

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rate schedule is available as an option for secondary service P-12 schools whose 12-month-average monthly minimum loads exceed 250 kW.

Service under this rate schedule is limited until the total projected revenue impact for customers taking service under SPS and STOD combined is $750,000 annually compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served; wherein such projected impacts shall be calculated on billing data for the most recent 12-month period available to the Companies. The Kentucky School Boards Association ("KSBA") will be responsible for proposing schools for participation in this optional rate and the order in which such schools are proposed. KU will calculate and provide to KSBA the projected revenue impact of each proposed school.

A customer electing to take service under this rate schedule who subsequently elects to take service under another rate schedule, may not be allowed to return to this optional rate for 12 months from the date of exiting this rate schedule.

This rate schedule will expire on July 1, 2020 or when KU files it next base rate case, whichever is earlier. Customers on this rate schedule will be transferred at that time to the rate schedule under which they were formerly served.

RATE

	Secondary	
Basic Service Charge per month:	$200.00	
Plus an Energy Charge per kWh:	$ 0.03244	
Plus a Maximum Load Charge per kW:		
Peak Demand Period:	$ 6.06	I
Intermediate Demand Period:	$ 4.55	I
Base Demand Period:	$ 5.13	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 measured load 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) the highest measured load in the preceding eleven (11) monthly billing periods, or
c) the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

DATE OF ISSUE: January 8, 2018

DATE EFFECTIVE: January 30, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2017-00266 dated December 19, 2017

School Power Service Pilot Program (SPS) and School Time-of-Day Service Pilot Program (STOD) are being eliminated

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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
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. Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed based on the measured kVA times 90 percent, at the applicable kW charge.

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

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

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

School Power Service Pilot Program (SPS) and School Time-of-Day Service Pilot Program (STOD) are being eliminated

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 80.2 N

Standard Rate **STOD**

SCHOOL TIME-OF-DAY SERVICE

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 sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by 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: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

School Power Service Pilot Program (SPS) and School Time-of-Day Service Pilot Program (STOD) are being eliminated

Kentucky Utilities Company

P.S.C. No. 18, Third Revision of Original Sheet No. 81
Canceling P.S.C. No. 18, Second Revision of Original Sheet No. 81

Standard Rate **OSL**

OUTDOOR SPORTS LIGHTING SERVICE

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rate schedule is available as an optional pilot program for secondary and primary service used by a customer for lighting specifically designed for outdoor fields which are normally used for organized competitive sports. Service under this rate schedule is limited to a maximum of twenty customers. Company will accept customers on a first-come-first-served basis.

RATE

	Secondary	Primary
Basic Service Charge per month:	$90.00	$240.00
Plus an Energy Charge per kWh of:	$ 0.03288	$ 0.03189
Plus a Maximum Load Charge per kW of:		
Peak Demand Period	$ 16.75	$ 16.88
Base Demand Period	$ 3.03	$ 3.03

Where:
the monthly billing demand for the Peak Demand Period is the greater of:
a) the maximum measured load in the billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods.
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the billing period, or
b) the highest measured load in the preceding eleven (11) monthly billing periods, or
c) if applicable, 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	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
Franchise Fee Rider	Sheet No. 90	
School Tax	Sheet No. 91	

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 81

Standard Rate Pilot **OSL** T

Outdoor Sports Lighting Service T

APPLICABLE
In all territory served.

AVAILABILITY T
Available as an optional pilot program for secondary and primary service used by a Customer for lighting specifically designed for outdoor fields which are normally used for organized competitive sports. Service under this rate schedule is limited to a maximum of twenty Customers. Company will accept Customers on a first-come-first-served basis. T

RATE

	Secondary	Primary	
Basic Service Charge per day:	$2.96	$7.89	T/I
Plus an Energy Charge per kWh of:	$0.03270	$0.03189	R
Plus a Maximum Load Charge per kW of:			
Peak Demand Period	$19.42	$19.57	I
Base Demand Period	$3.03	$2.87	R

Where:
the monthly billing demand for the Peak Demand Period is the greater of:
1. the maximum measured load in the billing period, or T
2. a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods. T

the monthly billing demand for the Base Demand Period is the greater of:
1. the maximum measured load in the billing period, or T
2. the highest measured load in the preceding eleven (11) monthly billing periods, or T
3. if applicable, the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. T

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	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	T
Franchise Fee	Sheet No. 90	D/T
School Tax	Sheet No. 91	

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 81.2 N

Standard Rate OSL

OUTDOOR SPORTS LIGHTING 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 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	Peak
Weekdays	All Hours	1 P.M. – 7 P.M.
Weekends	All Hours	

All other months of October continuously through April

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

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by 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: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 81.1

Standard Rate Pilot OSL T

Outdoor Sports Lighting Service T

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.

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	Peak
Weekdays	All Hours	1 P.M. – 7 P.M.
Weekends	All Hours	

All other months of October continuously through April

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

If a legal holiday falls on a weekday, it will be considered a weekday. N

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 85

Adjustment Clause **FAC**

Fuel Adjustment Clause

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all electric rate schedules.

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

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

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

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

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

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

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

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

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

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00221 dated December 20, 2012

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 85

Adjustment Clause **FAC**

Fuel Adjustment Clause

APPLICABLE

In all territory served.

AVAILABILITY T

This schedule is mandatory to all rate schedules. T

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.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 85.1
Canceling P.S.C. No. 18, Original Sheet No. 85.1

Adjustment Clause **FAC**
Fuel Adjustment Clause

(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.

(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).

(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 August 2015, and the base fuel factor is $0.02609 per kWh. T/R

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

D

DATE OF ISSUE: August 4, 2017

DATE EFFECTIVE: September 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2017-00003 dated July 31, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 85.1

Adjustment Clause **FAC**
Fuel Adjustment Clause

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.

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).

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 August 2015, and the base fuel factor is $0.02609 per kWh.

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After September 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2017-00003 dated July 31, 2017

Kentucky Utilities Company

P.S.C. No. 18, 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 Service Rate RS, Residential Time-of-Day Energy Rate RTOD-Energy, Residential Time-of-Day Demand Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, Retail Transmission Service Rate RTS, School Power Service Rate SPS, School Time-of-Day Service T
Rate STOD, and Outdoor Sports Lighting Service Rate OSL. Industrial customers who elect not to T
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:

DATE OF ISSUE: July 7, 2017

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, 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 Service Rate RS, Residential Time-of-Day Energy Rate RTOD-Energy, Residential Time-of-Day Demand Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, Retail
Transmission Service Rate RTS, and Outdoor Sports Lighting Service Rate OSL. Industrial T
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:

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On and After November 1, 2018

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 86.1

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

RATE (continued)

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, Residential Time-of-Day Energy Service, Volunteer Fire Department, General Service, and All Electric School customer classes is defined as the weighted average price per kWh of expected billings under the energy charges contained in the RS, RTOD-Energy, VFD, GS, and AES 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 RTOD-Demand, PS, TODS, TODP, RTS, T SPS, STOD, and OSL) is defined as the weighted average price per kWh represented T by the composite of the expected billings under the respective demand and energy charges in the upcoming twelve-month period, after deducting the variable costs included in the energy charges.

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

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

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

DSMI = DSM INCENTIVE

For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 86.1

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

RATE (continued)

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, Residential Time-of-Day Energy Service, Volunteer Fire Department, General Service, and All Electric School customer classes is defined as the weighted average price per kWh of expected billings under the energy charges contained in the RS, RTOD-Energy, VFD, GS, and AES 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 RTOD-Demand, PS, TODS, TODP, RTS, and T OSL) is defined as the weighted average price per kWh represented by the composite of the expected billings under the respective demand and energy charges in the upcoming twelve-month period, after deducting the variable costs included in the energy charges.

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

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

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

DSMI = DSM INCENTIVE

For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved

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P.S.C. No. 18, Original Sheet No. 86.2

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

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 Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day Demand Service Rate RTOD-Demand, Volunteer Fire Department Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Service Rate PS, Time-of-day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Service Rate RTS, School Power Service Rate SPS, School Time-of-Day T
Service Rate STOD, and Outdoor Sports Lighting Service Rate OSL shall be divided by T
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.

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P.S.C. No. 19, Original Sheet No. 86.2

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

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 Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day Demand Service Rate RTOD-Demand, Volunteer Fire Department Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Service Rate PS, Time-of-day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail
Transmission Service Rate RTS, and Outdoor Sports Lighting Service Rate OSL shall be T
divided by the expected kilowatt-hour sales for the upcoming twelve-month period to T
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.

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 86.3

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

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

DCCR = DSM CAPITAL COST RECOVERY

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

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

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

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

CHANGES TO DSMRC

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

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

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

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 86.3

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

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

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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

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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.

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Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 86.4
Cancelling P.S.C. No. 18, Original Sheet No. 86.4

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

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, RTOD-Energy, RTOD-Demand, and VFD Standard Electric Rate Schedules.

Residential Load Management / Demand Conservation
The Residential Load Management / Demand Conservation Program employs 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. For on-site audits conducted prior to April 1, 2018, customers are eligible for incentives N
of $150 or $1,000 based on customer purchased and installed energy efficiency measures and validated through a follow-up test. The follow-up test must be scheduled by September 1, N
2018. No follow-up tests or incentives will be available related to on-site audits conducted on N
or after April 1, 2018. N

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, and blower door tests, and installs weatherization and energy conservation measures. Qualified customers could receive energy conservation measures ranging from $0 to $2,100 based upon the customer's most recent twelve month energy usage and results of an energy audit.

Smart Energy Profile
The Smart Energy Profile Program provides a portion of KU's highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar local properties. 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. The Company will cease offering this program effective April 1, 2018. N

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State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 86.4

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

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, RTOD-Energy, RTOD-Demand, and VFD Standard Electric Rate Schedules.

Residential Load Management / Demand Conservation
The Residential Load Management / Demand Conservation Program employs 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.

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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, and blower door tests, and installs weatherization and energy conservation measures. Qualified customers could receive energy conservation measures ranging from $0 to $2,100 based upon the customer's most recent twelve month energy usage and results of an energy audit.

Smart Energy Profile
The Smart Energy Profile Program provides a portion of KU's highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar local properties. 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. The Company will cease offering this program effective April 1, 2018.

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State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 86.5
Cancelling P.S.C. No. 18, 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. The Company will cease offering this program effective April 1, 2018. All incentives will go to $0 at that time. A customer desiring an incentive must purchase a qualified item and request an application from the Company prior to April 1, 2018. All incentive applications, including proofs of purchase, must be received by September 1, 2018. N

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

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

Customer Education and Public Information
This program helps 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 three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. 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. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

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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. The Company will cease offering this program effective April 1, 2018. All incentives will go to $0 at that time. A customer desiring an incentive must purchase a qualified item and request an application from the Company prior to April 1, 2018. All incentive applications, including proofs of purchase, must be received by September 1, 2018.

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

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

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This program helps 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 three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. 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. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

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P.S.C. No. 18, First Revision of Original Sheet No. 86.6
Cancelling P.S.C. No. 18, Original Sheet No. 86.6

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

Residential Advanced Metering Systems Incentives:
The following Demand Side Management offering is available to residential customers receiving service from the Company on the RS Rate Schedule.

Advanced Metering Systems
The Advanced Metering Systems offering is designed to provide energy consumption data to customers on a more frequent basis than is traditionally available through monthly billing. The Program employs advanced meters to communicate hourly consumption data to customers through a website.

Commercial Customer Program Participation Incentives:
The following Demand Side Management programs are available to commercial customers receiving service from the Company on the GS, AES, PS, TODS, TODP, RTS, SPS, STOD, and OSL 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 86.9. T

Commercial Conservation / Commercial Incentives
The Commercial Conservation / Commercial Incentive Program is designed to increase the implementation of energy efficiency measures by providing financial incentives to assist with the replacement of aging and less efficient equipment and for new construction built beyond code requirements. The Program also offers an online tool providing recommendations for energy-efficiency improvements. Incentives available to all commercial customers are based upon a $100 per kW removed for calculated efficiency improvements completed by March 31, N
2018. Effective April 1, 2018, the incentives will be based upon a $0.03 per kWh of energy N
saved for calculated efficiency improvements. A prescriptive list provides customers with N
incentive values for various efficiency improvement projects. Additionally, a custom rebate is available based upon company engineering validation of sustainable energy savings. New T
construction rebates are available on savings over code plus bonus rebates for LEED certification.

- 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, Custom and New Construction Rebates

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 86.6

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

Residential Advanced Metering Systems Incentives:
The following Demand Side Management offering is available to residential customers receiving service from the Company on the RS Rate Schedule.

Advanced Metering Systems
The Advanced Metering Systems offering is designed to provide energy consumption data to customers on a more frequent basis than is traditionally available through monthly billing. The Program employs advanced meters to communicate hourly consumption data to customers through a website.

Commercial Customer Program Participation Incentives:
The following Demand Side Management programs are available to commercial customers receiving service from the Company on the GS, AES, PS, TODS, TODP, RTS, and OSL Standard T
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 86.9.

Commercial Conservation / Commercial Incentives
The Commercial Conservation / Commercial Incentive Program is designed to increase the implementation of energy efficiency measures by providing financial incentives to assist with the replacement of aging and less efficient equipment and for new construction built beyond code requirements. The Program also offers an online tool providing recommendations for energy-efficiency improvements. Incentives available to all commercial customers are based upon a $100 per kW removed for calculated efficiency improvements completed by March 31, 2018. Effective April 1, 2018, the incentives will be based upon a $0.03 per kWh of energy saved for calculated efficiency improvements. A prescriptive list provides customers with incentive values for various efficiency improvement projects. Additionally, a custom rebate is available based upon company engineering validation of sustainable energy savings. New construction rebates are available on savings over code plus bonus rebates for LEED certification.

- 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, Custom and New Construction Rebates

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 86.7

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Customer Education and Public Information
This program helps 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 three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. 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. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

School Energy Management Program
The School Energy Management program will facilitate the hiring and retention of qualified, trained energy specialists by public school districts to support facilitation of energy efficiency measures for public and independent schools under KRS 160.325.

Commercial Advanced Metering Systems Incentives:
The following Demand Side Management offering is available to residential customers receiving service from the Company on the GS Rate Schedule.

Advanced Metering Systems
The Advanced Metering Systems offering is designed to provide energy consumption data to customers on a more frequent basis than is traditionally available through monthly billing. The Program employs advanced meters to communicate hourly consumption data to customers through a website.

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State Regulation and Rates
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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 86.7

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Customer Education and Public Information
This program helps 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 three processes: a mass-media campaign, an elementary- and middle-school program, and training for home construction professionals. 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. The training for home construction professionals provides education about new building codes, standards and energy efficient construction practices which support high performance residential construction.

School Energy Management Program
The School Energy Management program will facilitate the hiring and retention of qualified, trained energy specialists by public school districts to support facilitation of energy efficiency measures for public and independent schools under KRS 160.325.

Commercial Advanced Metering Systems Incentives:
The following Demand Side Management offering is available to residential customers receiving service from the Company on the GS Rate Schedule.

Advanced Metering Systems
The Advanced Metering Systems offering is designed to provide energy consumption data to customers on a more frequent basis than is traditionally available through monthly billing. The Program employs advanced meters to communicate hourly consumption data to customers through a website.

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Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 86.8
Cancelling P.S.C. No. 18, Original Sheet No. 86.8

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

Current Program Incentive Structures

Residential Load Management / Demand Conservation

Switch Option:
- $3/month bill credit for June, July, August, and September per air conditioning unit or heat pump on single family home. R
- $2/month bill credit for June, July, August, and September per electric water heater (40 gallon minimum) or swimming pool pump on single family home.

D

Multi-family Option:
- Tenant - $2/month bill credit per customer for June, July, August, and September per air conditioning unit or heat pump. T/D

D

Residential Refrigerator Removal Program
The program provides $50 per working refrigerator or freezer.

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State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 86.8

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

Current Program Incentive Structures

Residential Load Management / Demand Conservation

Switch Option:
- $3/month bill credit for June, July, August, and September per air conditioning unit or heat pump on single family home.
- $2/month bill credit for June, July, August, and September per electric water heater (40 gallon minimum) or swimming pool pump on single family home.

Multi-family Option:
- Tenant - $2/month bill credit per customer for June, July, August, and September per air conditioning unit or heat pump.

Residential Refrigerator Removal Program
The program provides $50 per working refrigerator or freezer.

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Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 86.9
Cancelling P.S.C. No. 18, Original Sheet No. 86.9

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

Commercial Load Management / Demand Conservation

Switch Option

- $3 per month bill credit for June, July, August, and September for air conditioning units up to 5 tons. R D D

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.

- $15 per kW for verified load reduction during June, July, August, and September. R
- 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.

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State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 86.9

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

Commercial Load Management / Demand Conservation

Switch Option

- $3 per month bill credit for June, July, August, and September for air conditioning units up to 5 tons.

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.

- $15 per kW for verified load reduction during June, July, August, and September.
- The customer will have access to at least hourly load data for every month of the year which they remain enrolled in the program.
- Additional customer charges may be incurred for metering equipment necessary for this program at costs under other tariffs.

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Kentucky Utilities Company

P.S.C. No. 18, Second Revision of Original Sheet No. 86.10
Canceling P.S.C. No. 18, First Revision of Original Sheet No. 86.10

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day Demand Service Rate RTOD-Demand, and Volunteer Fire Department Service Rate VFD	Energy Charge	
DSM Cost Recovery Component (DCR)	$ 0.00155 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00012 per kWh	
DSM Incentive (DSMI)	$ 0.00002 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00063 per kWh	R
DSM Balance Adjustment (DBA)	$ 0.00011 per kWh	I
Total DSMRC for Rates RS, RTOD-Energy, RTOD-Demand, and VFD	$ 0.00243 per kWh	I

General Service Rate GS*	Energy Charge	
DSM Cost Recovery Component (DCR)	$ 0.00097 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00027 per kWh	
DSM Incentive (DSMI)	$ 0.00001 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00013 per kWh	
DSM Balance Adjustment (DBA)	$ 0.00020 per kWh	R
Total DSMRC for Rate GS	$ 0.00158 per kWh	R

All Electric School Rate AES	Energy Charge	
DSM Cost Recovery Component (DCR)	$ 0.00031 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00008 per kWh	
DSM Incentive (DSMI)	$ 0.00000 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00040 per kWh	R
DSM Balance Adjustment (DBA)	$ 0.00000 per kWh	R
Total DSMRC for Rate AES	$ 0.00079 per kWh	R

Power Service Rate PS*, Time of Day Secondary Service Rate TODS*, Time-of-Day Primary Service Rate TODP*, Retail Transmission Service Rate RTS*, School Power Service Rate SPS, School Time-of-Day Service Rate STOD, and Outdoor Sports Lighting Service Rate OSL	Energy Charge	
DSM Cost Recovery Component (DCR)	$ 0.00028 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00009 per kWh	
DSM Incentive (DSMI)	$ 0.00000 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00016 per kWh	
DSM Balance Adjustment (DBA)	$(0.00003) per kWh	R
Total DSMRC for Rates PS, TODS, TODP, RTS, SPS, STOD, and OSL	$ 0.00050 per kWh	R

* These charges do not apply to industrial customers taking service under these rates because the Company currently does not offer industrial DSM programs.

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State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Sheet No. 86.10

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day Demand Service Rate RTOD-Demand, and Volunteer Fire Department Service Rate VFD	Energy Charge	
DSM Cost Recovery Component (DCR)	$ 0.00155 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00012 per kWh	
DSM Incentive (DSMI)	$ 0.00002 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00063 per kWh	
DSM Balance Adjustment (DBA)	$ 0.00011 per kWh	
Total DSMRC for Rates RS, RTOD-Energy, RTOD-Demand, and VFD	$ 0.00243 per kWh	

General Service Rate GS*	Energy Charge	
DSM Cost Recovery Component (DCR)	$ 0.00097 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00027 per kWh	
DSM Incentive (DSMI)	$ 0.00001 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00013 per kWh	
DSM Balance Adjustment (DBA)	$ 0.00020 per kWh	
Total DSMRC for Rate GS	$ 0.00158 per kWh	

All Electric School Rate AES	Energy Charge	
DSM Cost Recovery Component (DCR)	$ 0.00031 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00008 per kWh	
DSM Incentive (DSMI)	$ 0.00000 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00040 per kWh	
DSM Balance Adjustment (DBA)	$ 0.00000 per kWh	
Total DSMRC for Rate AES	$ 0.00079 per kWh	

Power Service Rate PS*, Time of Day Secondary Service Rate TODS*, Time-of-Day Primary Service Rate TODP*, Retail Transmission Service Rate RTS*, and Outdoor Sports Lighting Service Rate OSL	Energy Charge	T
DSM Cost Recovery Component (DCR)	$ 0.00028 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00009 per kWh	
DSM Incentive (DSMI)	$ 0.00000 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00016 per kWh	
DSM Balance Adjustment (DBA)	$(0.00003) per kWh	
Total DSMRC for Rates PS, TODS, TODP, RTS, and OSL	$ 0.00050 per kWh	T

* These charges do not apply to industrial customers taking service under these rates because the Company currently does not offer industrial DSM programs.

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Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 87
Canceling P.S.C. No. 18, 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 PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC (including the Off-System Sales Tracker) 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; RTOD-Energy; RTOD-Demand; VFD; AES; LS; RLS; LE; and TE.
Group 2: Rate Schedules GS; PS; TODS; TODP; RTS; FLS; EVSE; EVC; SPS; STOD; and OSL.

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
   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.
   f) EAS is the total proceeds from emission allowance sales.
   g) BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse.
   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: July 11, 2018

DATE EFFECTIVE: July 9, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2017-00483 dated July 9, 2018

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 87

Adjustment Clause **ECR**

Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY T

This schedule is mandatory to all rate schedules listed in Section 1 of the General Index except T
Rate PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and T
FAC (including OSS) and DSM Adjustment Clauses. Rate schedules subject to this adjustment T
clause are divided into Group 1 or Group 2 as follows: T

Group 1: Rates RS; RTOD-Energy; RTOD-Demand; VFD; AES; LS; RLS; LE; and TE. T
Group 2: Rates GS; PS; TODS; TODP; RTS; FLS; EVSE; EVC; and OSL. 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 twelve (12) month T
average revenue for the current expense month and for Group 2 it is the twelve (12) month average T
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
   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.
   f. EAS is the total proceeds from emission allowance sales.
   g. BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse.
   h. Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183.

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Canceling P.S.C. No. 18, Original Sheet No. 87.1

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

DEFINITIONS (continued)

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.

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P.S.C. No. 19, Original Sheet No. 87.1

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

DEFINITIONS (continued)

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 twelve (12) months ending with T 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 twelve (12) T months ending with the current expense month. Base revenue includes 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 twelve T (12) months ending with the current expense month. Base non-fuel revenue includes T 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.

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 88

Adjustment Clause **OSS**

Off-System Sales Adjustment Clause

APPLICABLE.

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all electric rate schedules that are subject to the Fuel Adjustment Clause.

RATE

The monthly OSS Adjustment Factor per kWh delivered under each of the schedules to which this mechanism is applicable shall be calculated in accordance with the following formula:

OSS Adjustment Factor = 0.75 x [(P(m) / S(m)]

Where "P" is the net eligible margins from off-system power sales and "S" is the kWh sales in the current period (m) as defined in 807 KAR 5:056. The OSS Adjustment Factor will be applied as set out below.

1) The monthly OSS Adjustment Factor will be combined with the monthly FAC factor and billed as one.

2) Current expense month (m) shall be the second month preceding the month in which the combined FAC and OSS factor is billed.

3) The combined monthly FAC and OSS factor shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 88

Adjustment Clause **OSS**

Off-System Sales Adjustment Clause

APPLICABLE.
In all territory served.

AVAILABILITY T
Mandatory to all rate schedules that are subject to Adjustment Clause FAC. T

RATE

The monthly OSS Adjustment Factor per kWh delivered under each of the schedules to which this mechanism is applicable shall be calculated in accordance with the following formula:

OSS Adjustment Factor = 0.75 x [(P(m) / S(m)]

Where "P" is the net eligible margins from off-system power sales and "S" is the kWh sales in the current period (m) as defined in 807 KAR 5:056. The OSS Adjustment Factor will be applied as set out below.

1. The monthly OSS Adjustment Factor will be combined with the monthly FAC factor and billed as one.

2. Current expense month (m) shall be the second month preceding the month in which the combined FAC and OSS factor is billed.

3. The combined monthly FAC and OSS factor shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

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Kentucky Utilities Company

 N

Adjustment Clause **TCJA**

Tax Cuts and Jobs Act Surcredit

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all Standard Rate Schedules listed in Sections 1 and 3 of the General Index except PSA and Special Charges.

RATE

The monthly billing amount computed under each of the rate schedules to which this surcredit is applicable shall decrease by the Tax Cuts and Jobs Act (TCJA) Surcredit. The TCJA Surcredit will be distributed to the Company's customers based on the following:

TCJA Surcredit per kWh:

Residential (RS, RTOD-Energy, RTOD-Demand, VFD):	$0.00415
Non-Residential (all other Rate Schedules):	$0.00323

TERMS OF DISTRIBUTION

(1) The TCJA Surcredit shall be applied to the customer's bill following the rates and charges for electric service, but before application of the Environmental Cost Recovery Surcharge, Franchise Fee Rider, School Tax, and Home Energy Assistance Program.

(2) The TCJA Surcredit shall be effective April 1, 2018 and continued through April 30, 2019 at the rates specified above.

(3) The TCJA Surcredit amounts listed on this page are interim amounts that are subject to change once the Public Service Commission issues a final decision in Case No. 2018-00034.

(4) In the event that the Company's base rates do not change on May 1, 2019, the TCJA Surcredit will continue at the following rates:

TCJA Surcredit per kWh:

Residential (RS, RTOD-Energy, RTOD-Demand, VFD):	$0.00337
Non-Residential (all other Rate Schedules):	$0.00262

(5) The TCJA Surcredit shall terminate when base rates are changed following an application requesting a change in base rates.

DATE OF ISSUE: April 5, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated March 20, 2018 and modified March 28, 2018

Tax Cuts and Jobs Act Surcredit Adjustment Clause (TCJA) is being eliminated

Kentucky Utilities Company

P.S.C. No. 18, 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.
4) At its option, a governmental body imposing a franchise fee shall not be billed for that portion of a franchise fee, applied to services designated by the governmental body, that would ultimately be repaid to the governmental body.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: May 26, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 90

Adjustment Clause **FF**

Franchise Fee T

APPLICABLE

In all territory served.

AVAILABILITY T

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 rate T schedules.

BILLING T

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 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.
4. At its option, a governmental body imposing a franchise fee shall not be billed for that portion of a franchise fee, applied to services designated by the governmental body that would ultimately be repaid to the governmental body.

TERM OF CONTRACT

As agreed to in the franchise agreement. Company will not calculate or collect any such fees, T
taxes, or charges pursuant to expired, lapsed, or otherwise invalid, ineffective or inapplicable T
ordinances, franchise agreements, or other governmental enactment. T

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 90.1

Adjustment Clause **FF**
Franchise Fee Rider

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: July 7, 2017

DATE EFFECTIVE: October 16, 2003

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 90.1

Adjustment Clause **FF**
Franchise Fee

SECTIONS APPLICABLE ONLY TO FRANCHISE FEE AGREEMENTS DATED BEFORE September 21, 2011 N T

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.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, 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: July 7, 2017

DATE EFFECTIVE: August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 91

Adjustment Clause **ST**

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APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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RATE

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DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After August 1, 2010

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 92

Adjustment Clause **HEA**

Home Energy Assistance Program

APPLICABLE
In all territory served.

AVAILABILITY
To all residential customers.

RATE
$0.30 per month. T/I

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

PURPOSE
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: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 92

Adjustment Clause **HEA**

Home Energy Assistance Program

APPLICABLE
In all territory served.

AVAILABILITY
To all residential Customers.

RATE
$0.30 per month.

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

PURPOSE
Proceeds from this charge will be used to fund residential low-income Home Energy Assistance programs, which have been designed through a collaborative advisory process and approved by the Commission. T T

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, 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, unless any rate or rider under which you take service explicitly states otherwise. T
- 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: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 95

Terms and Conditions

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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.
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  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: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 18, 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 to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions in each rate schedule, and which shall constitute a part of all applications and contracts for service. T T T

COMPANY AS A FEDERAL CONTRACTOR

The United Nations Convention on Contracts for the International Sale of Goods is specifically disclaimed and excluded and will not apply to or govern agreements between customers and Company.

To the extent Company is a federal contractor, Company and its subcontractors shall abide by the requirements of 41 CFR 60-741.5(a). This regulation prohibits discrimination against qualified individuals on the basis of disability, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified individuals with disabilities.

To the extent Company is a federal contractor, Company and its subcontractors shall abide by the requirements of 41 CFR 60-300.5(a). This regulation prohibits discrimination against qualified protected veterans, and requires affirmative action by covered prime contractors and subcontractors to employ and advance in employment qualified protected veterans.

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.

CUSTOMER GENERATION

All existing and future installations of equipment for the purpose of electric generation that is intended to run in parallel with utility service, regardless of the length of parallel operation, 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. T

ASSIGNMENT

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

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, 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 Kentucky Public Service Commission.

COMPANY TERMS AND CONDITIONS

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ASSIGNMENT

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

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 96.1

TERMS AND CONDITIONS

General

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: July 7, 2017

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 96.1

Terms and Conditions
General

RENEWAL OF CONTRACT

If, upon the expiration of any service contract for a specified term, 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: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 97

TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

A written, in-person, electronic, or oral application or contract, properly executed, will be required before Company is obligated to render electric service. Company may require any party applying for service to provide some or all of the following information for the party desiring service: full legal name, address, full Social Security Number or other taxpayer identification number, date of birth (if applicable), relationship of the applying party to the party desiring service, and any other information Company deems necessary for legal, business, or debt-collection purposes. Company shall have the right to reject for valid reasons any such application or contract, including the applying party's refusal to provide requested information. T

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.

If Company or Customer terminates Customer's service under a rate schedule that contains demand charges and Customer subsequently applies to Company to reestablish service to the same premise or facility, Company must determine monthly billing demand for the reestablished service as though Customer had continuously taken service from the time of service termination through the reestablishing of service to Customer. For the purpose of determining the monthly billing demand described in the preceding sentence, the demand to be used for the period during which Customer did not take service from Company shall be the actually recorded demand, if any, for the premise or facility during that period. The preceding two sentences will not apply if Company determines, in its sole discretion, that material changes to Customer's facilities, processes, or practices justify establishing a new Contract Demand for the reestablished service. T

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 97

Terms and Conditions

Customer Responsibilities

APPLICATION FOR SERVICE

A written, in-person, electronic, or oral application or contract, properly executed, will be required before Company is obligated to render electric service. Company may require any party applying for service to provide some or all of the following information for the party desiring service: full legal name, address, full Social Security Number or other taxpayer identification number, date of birth (if applicable), relationship of the applying party to the party desiring service, and any other information Company deems necessary for legal, business, or debt-collection purposes. Company shall have the right to reject for valid reasons any such application or contract, including the applying party's refusal to provide requested information.

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 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. T

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.

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DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 97.1

TERMS AND CONDITIONS

Customer Responsibilities

OPTIONAL RATES T

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

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

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

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

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

CUSTOMER'S EQUIPMENT AND INSTALLATION

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

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

OWNER'S CONSENT TO OCCUPY

Customer shall grant easements and rights-of-way on and across Customer's property at no cost to Company. T

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 97.1

Terms and Conditions
Customer Responsibilities

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 (12) 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 Customer will at all times be served under the most beneficial rate.

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

CUSTOMER'S EQUIPMENT AND INSTALLATION

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

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

OWNER'S CONSENT TO OCCUPY

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

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On and After July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 97.2

TERMS AND CONDITIONS

Customer Responsibilities

ACCESS TO PREMISES AND EQUIPMENT T

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.

POWER FACTOR

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

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

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

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

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

LIABILITY

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

T

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 97.2

Terms and Conditions
Customer Responsibilities

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.

POWER FACTOR

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

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

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

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 97.3

TERMS AND CONDITIONS

Customer Responsibilities

NOTICE TO COMPANY OF CHANGES IN CUSTOMER'S LOAD

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

PERMITS

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

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

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

CHANGES IN SERVICE

Where Customer is receiving service and desires relocation or change in facilities not supported by additional load, Customer is responsible for the cost of the relocation or change in facilities through a Non-Refundable Advance.

DATE OF ISSUE: July 7, 2017

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 97.3

Terms and Conditions
Customer Responsibilities

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DATE OF ISSUE: September 28, 2018

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 98

TERMS AND CONDITIONS

Company Responsibilities

METERING

The electricity used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. Company has the right to install any meter or meters it deems in its sole discretion to be necessary or prudent to serve any customer, including without limitation a digital, automated meter reading, automated metering infrastructure, or advanced metering systems meter or 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. T

POINT OF DELIVERY OF ELECTRICITY

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

EXTENSION OF SERVICE

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

COMPANY'S EQUIPMENT AND INSTALLATION

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

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

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DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 98

Terms and Conditions

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DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 98.1

TERMS AND CONDITIONS

Company Responsibilities

Notwithstanding the provisions of 807 KAR 5:006, Section 14(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.

COMPANY NOT LIABLE FOR INTERRUPTIONS

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

COMPANY NOT LIABLE FOR DAMAGE ON CUSTOMER'S PREMISES

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

LIABILITY

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

FIRM SERVICE

Where a customer-generator supplies all or part of the customer-generator's own load and desires Company to provide service for that load, the customer-generator must contract for such T
service, otherwise Company has no obligation to supply the non-firm service. T

DATE OF ISSUE: July 7, 2017

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 98.1

Terms and Conditions
Company Responsibilities

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On and After July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 99

TERMS AND CONDITIONS

Character of Service

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

SECONDARY VOLTAGES

Residential Service -

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

Non-Residential Service -

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

PRIMARY VOLTAGES

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

TRANSMISSION VOLTAGES

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

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

RESTRICTIONS

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

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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

Kentucky Utilities Company

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Terms and Conditions

Character of Service

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

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Residential Service -

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

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

PRIMARY VOLTAGES

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

TRANSMISSION VOLTAGES

According to location, 69,000 volts, 138,000 volts, 161,000 volts, or 345,000 volts. T

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

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   a. In the event Company is required to provide transformation to reduce an available voltage to a lower voltage for delivery to a Customer, Customer shall be served at the rate applicable to the lower voltage; provided, however, that if the same rate is applicable to both the available voltage and the delivery voltage, Customer may be required to make a non-refundable payment to reflect the additional investment required to provide service.
   b. The available voltage shall be the voltage on that distribution or transmission line which Company designates as being suitable from the standpoint of capacity and other operating characteristics for supplying the requirements of Customer.

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On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 100

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

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

1. **DEFINITION OF RESIDENTIAL RATE** - Residential rates are based on service to single family units served through a single meter. Such service may include incidental usage of electricity for home occupations, such as the office of a physician, surgeon, dentist, musician or artist when such occupation is practiced by Customer in Customer's residence. Service to both a single family unit and a detached structure may both be served through a single meter, regardless of the meter location, and qualify for the residential service provided the consumption in the non-residential portion of the detached structure is incidental.

2. **DEFINITION OF SINGLE FAMILY UNIT** - A single family unit is a structure or part of a structure used or intended to be used as a home, residence, or sleeping place by one or more persons maintaining a common household. Residential service is not available to transient multi-family structures including, but not limited to, hotels, motels, studio apartments, college dormitories, or any structure without a permanent foundation or attached to sanitation facilities. Fraternity or sorority organizations associated with educational institutions may be classified as residential and billed at the residential rate.

3. **DETACHED STRUCTURES** - If Customer has detached structures that are located at such distance from Customer's residence as to make it impracticable to supply service through customer's residential meter, the separate meter required to measure service to the detached structures will be considered a separate service and billed as a separate customer.

4. **POWER REQUIREMENT -** Single-phase power service used for domestic purposes will be permitted under Residential Rates RS, RTOD-Energy, and RTOD-Demand when measured through the residential meter subject to the conditions set forth below: T

   (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

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 100

Terms and Conditions

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2. **DEFINITION OF SINGLE FAMILY UNIT** - A single family unit is a structure or part of a structure used or intended to be used as a home, residence, or sleeping place by one or more persons maintaining a common household. Residential service is not available to transient multi-family structures including, but not limited to, hotels, motels, studio apartments, college dormitories, or any structure without a permanent foundation or attached to sanitation facilities. Fraternity or sorority organizations associated with educational institutions may be classified as residential and billed at the residential rate.

3. **DETACHED STRUCTURES** - If Customer has detached structures that are located at such distance from Customer's residence as to make it impracticable to supply service through Customer's residential meter, the separate meter required to measure service to the detached structures will be considered a separate service and billed as a separate Customer.

4. **POWER REQUIREMENT -** Single-phase power service used for domestic purposes will be permitted under Residential Rates RS, RTOD-Energy, and RTOD-Demand when measured through the residential meter subject to the conditions set forth below:

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

   b. Single-phase motors of new central residential cooling installations with total locked-rotor ratings of not to exceed 125 amperes (inclusive of any auxiliary motors arranged for simultaneous starting with the compressor) may be connected for across-the-line starting provided the available capacity of Company's electric distribution facilities at desired point of supply is such that, in Company's judgment, the starting of such motors will not result in excessive voltage dips and undue disturbance of lighting service and television reception of

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 100.1

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

nearby electric customers. However, except with Company's express written consent, no new single-phase central residential cooling unit having a total lock-rotor rating in excess of 125 amperes inclusive of auxiliary motors arranged for simultaneous starting with the compressor) shall hereafter be connected to Company's lines, or be eligible for electric service therefrom, unless it is equipped with an approved type of current-limiting device for starting which will reduce the initial and incremental starting current inrush to a maximum of 100 amperes per step. Company shall be furnished with reasonable advance notice of any proposed central residential cooling installation.

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

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

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Terms and Conditions
Residential Rate Specific Terms and Conditions

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

d. Any motor or motors served through a separate meter will be billed as a separate Customer.

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 101

TERMS AND CONDITIONS

BILLING

METER READINGS AND BILLS

As used in the entirety of this Tariff, "meter reading" and similar terms shall include data collected remotely from automated meter reading, automated meter infrastructure, advanced metering systems, and other electronic meter equipment or systems capable of delivering usage data to Company. A physical, manual reading of a meter is not required to constitute a "meter reading." T

Each bill for utility service shall be issued in compliance with 807 KAR 5:006, Section 7.

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

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

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

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

Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within sixteen (16) business days (no less than twenty-two (22) calendar days) from date of rendition thereof. If full payment is not received by 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.

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Terms and Conditions

Billing

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Each bill for utility service shall be issued in compliance with 807 KAR 5:006, Section 7.

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's 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 (30) days, unless an applicable rate schedule has a daily Basic Service Charge, in which case a full daily Basic Service Charge will be charged to a customer for each day or partial day during which the customer's account was open and served under that rate schedule. N N N

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

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

Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within sixteen (16) business days (no less than twenty-two (22) calendar days) from date of rendition thereof. If full payment is not received by 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 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 Company receives Customer's payment within fifteen (15) days after the date on which Company issues Customer's bill.

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

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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 (2) or more meters will not be combined except where Company's operating convenience requires the installation of two (2) or more meters upon Customer's premises instead of one (1) meter.

CUSTOMER RATE ASSIGNMENT

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.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, 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 (2) or more meters will not be combined except where Company's operating convenience requires the installation of two (2) or more meters upon Customer's premises instead of one (1) meter.

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 101.2

TERMS AND CONDITIONS

BILLING

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

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."

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 101.2

Terms and Conditions
Billing

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 101.3

TERMS AND CONDITIONS

BILLING

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 quarterly. In addition, Company may investigate usage deviations brought to its attention as a result of its ongoing meter reading or billing processor customer inquiry. Should an unusual deviation in Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of Customer's meter reading and billing records, Company may contact Customer to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether the results show the meter is within the limits allowed by 807 KAR 5:041, Section 17(1). Company will notify Customer of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 11(4) and (5).

RESALE OF ELECTRIC ENERGY

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

MINIMUM CHARGE

Without limiting the foregoing, the Demand Charge shall be due regardless of any event or occurrence that might limit (a) Customer's ability or interest in operating Customer's facility, including, but without limitation, any acts of God, fires, floods, earthquakes, acts of government, terrorism, severe weather, riot, embargo, changes in law, or strikes or (b) Company's ability to serve customer.

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 101.3

Terms and Conditions
Billing

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In order to detect unusual deviations in individual Customer consumption, Company will monitor the usage of each Customer at least once quarterly. In addition, Company may investigate usage deviations brought to its attention as a result of its ongoing meter reading or billing processor Customer inquiry. Should an unusual deviation in Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of Customer's meter reading and billing records, Company may contact Customer to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether the results show the meter is within the limits allowed by 807 KAR 5:041, Section 17(1). Company will notify Customer of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 11(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 Basic Service Charge and Demand Charge shall apply and be T
due for all times during which a customer's account is open, regardless of any event or T
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.

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Kentucky Utilities Company

P.S.C. No. 18, 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 8, except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, 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 six (6) 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 Rate RS - Sheet No. 5, Residential Time-of-Day Energy Service Rate RTOD-Energy - Sheet No. 6, and Residential Time-of-Day Demand Service Rate RTOD-Demand - Sheet No. 7.
2) The deposit for a residential customer is in the amount of $160.00, which is calculated in accordance with 807 KAR 5:006, Section 8(1)(d)(2).
3) Company will retain Customer's deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.
4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.

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Kentucky Utilities Company

P.S.C. No. 19, 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 8, except for Customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, 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 six (6) 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 Rates RS - Sheet No. 5, RTOD-Energy - Sheet No. 6, and RTOD-Demand - Sheet No. 7.
2. The deposit for a residential Customer is in the amount of $160.00, which is calculated in accordance with 807 KAR 5:006, Section 8(1)(d)(2).
3. Company will retain Customer's deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.
4. If a deposit is held longer than eighteen (18) months, the deposit will be recalculated at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 102.1

TERMS AND CONDITIONS

DEPOSITS

RESIDENTIAL (Continued)

5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise become a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

GENERAL SERVICE

1) General service customers are those customers served under General Service Rate GS, Sheet No. 10.
2) The deposit for a general service customer is in the amount of $240.00, which is calculated in accordance with 807 KAR 5:006, Section 8(1)(d)(2). The deposit for a General Service customer may be waived when the General Service delivery is to a detached building used in conjunction with a Residential Service and the General Service usage is no more than 300 kWh per month.
3) Company shall retain Customer's deposit as long as Customer remains on service.
4) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten (10%) percent, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

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OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential or general service, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR 5:006, Section 8(1)(d)(1).
2) For customers not meeting the parameters of GENERAL SERVICE ¶ 2, above, Company may retain Customer's deposit as long as Customer remains on service.
3) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten (10%) percent, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise become a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 102.1

Terms and Conditions
Deposits

RESIDENTIAL (Continued)

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.

GENERAL SERVICE

1. General service Customers are those Customers served under General Service Rate GS, Sheet No. 10.
2. The deposit for a general service Customer is in the amount of $240.00, which is calculated in accordance with 807 KAR 5:006, Section 8(1)(d)(2). The deposit for a General Service Customer may be waived when the General Service delivery is to a detached building used in conjunction with a Residential Service and the General Service usage is no more than 300 kWh per month.
3. Company shall retain Customer's deposit as long as Customer remains on service.
4. For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten (10%) percent, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5. If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1. The deposit for all other Customers, those not classified herein as residential or general service, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR 5:006, Section 8(1)(d)(1).
2. For Customers not meeting the parameters of GENERAL SERVICE ¶ 2, above, Company may retain Customer's deposit as long as Customer remains on service.
3. For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten (10%) percent, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4. If Customer fails to maintain a satisfactory payment or credit record, or otherwise become a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After July 1, 2015

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 103

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to any residential customer served under Residential Service Rate RS or any general service customer served under General Service Rate GS. If a residential customer, who is currently served under Residential Service Rate RS and is currently enrolled in the Budget Payment Plan, elects to take service under Residential Time-of-Day Energy Service Rate RTOD-Energy or Residential Time-of-Day Demand Service Rate RTOD-Demand, such customer would be removed from the Budget Payment Plan and restored to regular billing.

Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in this plan at any time.

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

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

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

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State Regulation and Rates
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P.S.C. No. 19, Original Sheet No. 103

Terms and Conditions

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Company's Budget Payment Plan is available to any residential Customer served under Residential Service Rate RS or any general service Customer served under General Service Rate GS. If a residential Customer, who is currently served under Residential Service Rate RS and is currently enrolled in the Budget Payment Plan, elects to take service under Residential Time-of-Day Energy Service Rate RTOD-Energy or Residential Time-of-Day Demand Service Rate RTOD-Demand, such Customer would be removed from the Budget Payment Plan and restored to regular billing.

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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 a 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.

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State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00371 dated June 30, 2015

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 104

TERMS AND CONDITIONS

Bill Format

T

Mailed **7/3/17** for Account # **3000-0000-0000**

AMOUNT DUE	DUE DATE
$129.79	9/26/17

a PPL company

BILLING SUMMARY

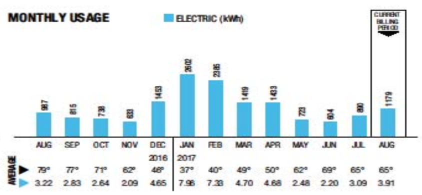
Previous Balance	99.21
Payment(s) Received	99.21
Balance as of 6/30/17	**$ 0.00**
Current Electric Charges	121.32
Current Taxes and Fees	8.47
Total Current Charges as of 6/30/17	**$129.79**
Total Amount Due	**$129.79**

Account Name:	JOHN DOE
Service Address:	1234 Anywhere Street LEXINGTON KY
Online Payments:	lge-ku.com
Telephone Payments:	(859) 255-0394, press 1-2-3 24 hours a day; $2.25 fee
Customer Service:	(859) 255-0394 M-F, 7am-7pm ET
Walk-in Center:	1 Quality Street Lexington, KY 40507 M-F, 8am-5pm ET

Next read will occur 9/6/17 - 9/8/17 (Meter Read Portion 05)

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	65°	79°
Number of Days Billed	31	31
Avg. Electric Charges per Day	$3.91	$3.22
Avg. Electric Usage per Day (kWh)	38.03	31.84



Please return only this portion with your payment. Make checks payable to KU and write your account number on your check.

Amount Due **9/26/17**	**$129.79**
After Due Date, Pay this Amount:	$ 133.68
WinterCare Donation:	
Total Amount Enclosed:	

Account # **3000-0000-0000**
Service Address: 1234 Anywhere Street

a PPL company
PO Box 9001954
Louisville, KY 40290-1954

JOHN DOE
1234 ANYWHERE STREET
LEXINGTON, KY 40500-0000

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2016-00370 dated June 22, 2017 and modified June 29, 2017

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 104

Terms and Conditions

Bill Format

T

Mailed **9/17/18** for Account # **3000-0000-0004**

AMOUNT DUE	DUE DATE
$131.80	10/11/18

a PPL company

BILLING SUMMARY

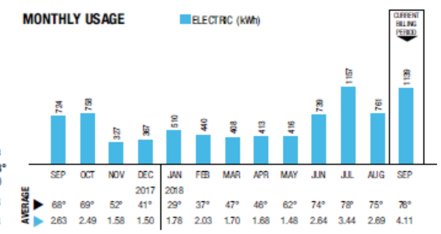
Previous Balance	83.48
Payment(s) Received	-83.48
Balance as of 9/14/18	**$0.00**
Current Electric Charges	123.19
Current Taxes and Fees	8.61
Total Current Charges as of 9/14/18	**$131.80**
Total Amount Due	**$131.80**

Account Name:	JANE DOE
Service Address:	220 W Main St LEXINGTON KY
Online Payments:	lge-ku.com
Telephone Payments:	(859) 255-0394, press 1-2-3 24 hours a day; $2.00 fee
Customer Service:	(859) 255-0394 M-F, 7am-7pm ET
Walk-in Center:	1 Quality Street Lexington, KY 40507 M-F, 8am-5pm ET

Next read will occur 10/15/18 - 10/17/18 (Meter Read Portion 10)

BILLING PERIOD AT-A-GLANCE

	THIS YEAR	LAST YEAR
Average Temperature	76°	68°
Number of Days Billed	30	30
Avg. Electric Charges per Day	$4.11	$2.63
Avg. Electric Usage per Day (kWh)	37.97	24.13



Please return only this portion with your payment. Make checks payable to KU and write your account number on your check.

Amount Due **10/11/18**	**$131.80**
After Due Date, Pay this Amount:	$135.75
WinterCare Donation:	
Total Amount Enclosed:	**AUTOPAY**

$131.80 will be deducted from your account on payment due date

Account # **3000-0000-0004**
Service Address: 220 W Main St

#9160900041#

a PPL company
PO Box 25212
Lehigh Valley, PA 18002-5212

JANE DOE
220 W MAIN ST
LEXINGTON, KY 40514-1000

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After November 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 104.1

TERMS AND CONDITIONS

Bill Format

T

Page 2 Account # **3000-0000-0000**

CURRENT USAGE

ELECTRIC	
Meter Reading Information	**Meter # L234635**
Actual (R) kWh Reading on 8/7/17	23179
Previous (R) kWh Reading on 7/7/17	22000
Current kWh Usage	1179
Meter Multiplier	1
Metered kWh Usage	**1179**

CURRENT CHARGES

ELECTRIC	Rate: Residential Service
Basic Service Charge	12.25
Energy Charge ($0.09078 x 1,179 kWh)	107.03
Electric DSM ($0.00290 x 1,179 kWh)	3.42
Fuel Adjustment ($-0.00509 x 1,179 kWh)	-6.00
Environmental Surcharge (3.700% x $116.70)	4.32
Home Energy Assistance Fund Charge	0.30
Total Charges	**$121.32**

Taxes & Fees	
Rate Increase For School Tax (3.00% x $121.02)	3.63
Franchise Fee-Lexington-Fayette (4.00% x $121.02)	4.84
Total Taxes and Fees	**$8.47**

BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $3.89

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

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MRU05311745, G000000
P99.21
PF:Y eB:P

RECYCLE THE OLD
REBATE THE NEW

We'll haul away your old, working fridge or freezer and pay you **$50**. You can earn up to **$300** when you upgrade to ENERGY STAR® certified appliances.
Visit lge-ku.com/savingenergy

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: July 1, 2017

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 104.1

Terms and Conditions
Bill Format

T

Page 2 Account # **3000-0000-0004**

CURRENT USAGE

ELECTRIC	
Meter Reading Information	**Meter # 7000000**
Actual (R) kWh Reading on 9/14/18	14671
Actual (R) kWh Reading on 8/15/18	13532
Current kWh Usage	1139
Meter Multiplier	1
Metered kWh Usage	**1139**

CURRENT CHARGES

ELECTRIC	Rate: Residential Service
Basic Service Charge ($0.53 x 30 days)	15.90
Energy Charge ($0.09552 x 1139 kWh)	108.80
Electric DSM ($0.00243 x 1139 kWh)	2.77
Fuel Adjustment ($-0.00303 x 1139 kWh)	-3.45
Environmental Surcharge (0.910% CR x $124.02)	-1.13
Home Energy Assistance Fund Charge	0.30
Total Charges	**$123.19**

Taxes & Fees	
Rate Increase For School Tax (3.00% x $122.89)	3.64
Franchise Fee-Lexington-Fayette (4.00% x $122.89)	4.86
Total Taxes and Fees	**$8.61**

BILLING INFORMATION

Late Payment Charge
Late Charge to be Assessed After Due Date $3.95

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

NATIONAL PREPAREDNESS MONTH

DISASTERS HAPPEN. PREPARE NOW. LEARN HOW.
lge-ku.com/safety/preparedness

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MRU10311510, G000000
P83.48
PF:Y eB:P

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00294 dated ____

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 105

TERMS AND CONDITIONS

Discontinuance of Service

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

A. When Company's or Commission's rules and regulations have not been complied with. However, service may be discontinued or refused only after Company has made a reasonable effort to induce Customer to comply with its rules and then only after Customer has been given at least ten (10) days written notice of such intention, mailed or otherwise delivered, including, but not limited to, electronic mail, to Customer's 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 Customer's or Applicant's 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 (either mailed or otherwise delivered, including, but not limited to, electronic mail) 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 15(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 15(1)(f). Final Bills transferred following a T

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 105

Terms and Conditions

Discontinuance of Service

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

1. 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 or otherwise delivered, including, but not limited to, electronic mail, to Customer's last known address.

2. 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.

3. When Customer or Applicant refuses or neglects to provide reasonable access and/or easements to and on Customer's or Applicant's 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 (either mailed or otherwise delivered, including, but not limited to, electronic mail) of Company's intention to discontinue or refuse service.

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

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

6. When directed to do so by governmental authority.

7. 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 15(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 15(1)(f). Final Bills transferred following a

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

TERMS AND CONDITIONS

Discontinuance of Service

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. T

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 Customer's 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 (either mailed or otherwise delivered, including, but not limited to, electronic mail), of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance.

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

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

Terms and Conditions
Discontinuance of Service

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 105.2

TERMS AND CONDITIONS

Discontinuance 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 assessment of the charges under the Unauthorized Reconnect Charge provision of Special Charges incurred by reason of the fraudulent use. T T T

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 (either mailed or otherwise delivered, including, but not limited to, electronic mail) based on Customer's payment history provided Company continues to provide the required ten (10) days written notice prior to discontinuance of service.

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Lexington, Kentucky

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P.S.C. No. 19, Original Sheet No. 105.2

Terms and Conditions
Discontinuance of Service

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 106

TERMS AND CONDITIONS

Line Extension Plan

A. AVAILABILITY

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

B. DEFINITIONS

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

C. GENERAL

1) All extensions of service will be made through the use of overhead facilities except as provided in these rules.
2) Customer requesting service which requires an extension(s) shall furnish to Company, at no cost, properly executed easement(s) for right-of-way across Customer's property to be served.
3) Customer requesting extension of service into a subdivision, subject to the jurisdiction of a public commission, board, committee, or other agency with authority to zone or otherwise regulate land use in the area and require a plat (or Plan) of the subdivision, Customer shall furnish, at no cost, Company with the plat (or plan) showing street and lot locations with utility easement and required restrictions. Plats (or plans) supplied shall have received final approval of the regulating body and recorded in the office of the appropriate County Court Clerk when required. Should no regulating body exist for the area into which service is to be extended, Customer shall furnish Company the required easement.
4) The title to all extensions, rights-of way, permits, and easements shall be and remain with Company.

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 106

Terms and Conditions

Line Extension Plan

1. AVAILABILITY T

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

2. DEFINITIONS T

a "Company" shall mean Kentucky Utilities Company. T
b. "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. T T
c. "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. T
d. "Permanent Service" shall mean service contracted for under the terms of the applicable rate schedule but not less than one (1) year and where the intended use is not seasonal, intermittent, or speculative in nature. T
e. "Commission" shall mean the Kentucky Public Service Commission. T

3. GENERAL T

a. All extensions of service will be made through the use of overhead facilities except as provided in these rules. T
b. 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. T
c. 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. T
d. The title to all extensions, rights-of way, permits, and easements shall be and remain with Company. T

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 106.1

TERMS AND CONDITIONS

Line Extension Plan

C. GENERAL (continued)

5) Customer must agree in writing to take service when the extension is completed and have Customer's building or other permanent facility wired and ready for connection.
6) 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
feasible the capital expenditure involved and provided such extensions are made to other customers under similar conditions.
7) 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.
8) 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.

D. NORMAL LINE EXTENSIONS

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

E. OTHER LINE EXTENSIONS

1) In accordance with 807 KAR 5:041, Section 11(2), Company shall provide to Customer requesting permanent service a line extension in excess of 1,000 feet per customer but Company may require the total cost of the footage in excess of 1,000 feet per customer, based on the average cost per foot of the total extension, be deposited with Company by Customer.
2) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension for each additional customer connected during that year directly to the original extension for which the deposit was made.
3) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension less the length of the lateral or extension for each additional customer connected during that year by a lateral or extension to the original extension for which the deposit was made.
4) 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.

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State Regulation and Rates
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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 106.1

Terms and Conditions
Line Extension Plan

3. GENERAL (continued) T

e. Customer must agree in writing to take service when the extension is completed and have Customer's building or other permanent facility wired and ready for connection. T
f. 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
feasible the capital expenditure involved and provided such extensions are made to other Customers under similar conditions. T
g. 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. T
h. 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

4. NORMAL LINE EXTENSIONS T

a. In accordance with 807 KAR 5:041, Section 11(1), Company will provide, at no cost, a line extension of up to 1,000 feet to Customer requesting permanent service where the installed transformer capacity does not exceed 25 kVA. T
b. Where Customer requires poly-phase distribution service or transformer capacity in excess of 25 kVA and Company provides such facilities, Company shall provide at its own expense the requested line extension, but only to the extent that the cost of the requested extension does not exceed the lesser of (i) the cost of a comparable overhead extension (if an underground extension is requested) or (ii) five (5) times Customer's estimated annual net revenue, where "net revenue" is defined as Customer's total revenue less base fuel, Fuel Adjustment Clause, Off-System Sales, Demand Side Management, franchise fees, and school taxes. Company may require Customer to pay in advance a non-refundable amount for the additional cost above the five (5) times net revenue calculation to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ a. above. Customer must commit to a minimum contract term of five (5) years. T N N N N N N N T T N

5. OTHER LINE EXTENSIONS T

a. 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. T
b. After the ten (10) year period following the line extension, 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 the first ten (10) year period directly to the original extension for which the deposit was made. T T
c. After the ten (10) year period following the line extension, 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 the first ten (10) year period by a lateral or extension to the original extension for which the deposit was made. T T T
d. 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. T

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 106.2

TERMS AND CONDITIONS

Line Extension Plan

E. OTHER LINE EXTENSIONS (continued)

5) Where Customer requires poly-phase service or transformer capacity above 25 kVA per customer and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in OTHER LINE EXTENSIONS ¶ 1 above.

F. OVERHEAD LINE EXTENSIONS TO SUBDIVISIONS

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

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 Orders.
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.

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Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 106.2

Terms and Conditions
Line Extension Plan

5. OTHER LINE EXTENSIONS (continued)

e. Where Customer requires poly-phase distribution service or transformer capacity in excess of 25 kVA and Company provides such facilities, Company shall provide at its own expense the requested line extension, but only to the extent that the cost of the requested extension does not exceed the lesser of (i) the cost of a comparable overhead extension (if an underground extension is requested) or (ii) five (5) times Customer's estimated annual net revenue, where "net revenue" is defined as Customer's total revenue less base fuel, Fuel Adjustment Clause, Demand Side Management, franchise fees, and school taxes. Company may require Customer to pay in advance a non-refundable amount for the additional cost above the five (5) times net revenue calculation to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ a. above.

6. OVERHEAD LINE EXTENSIONS FOR SUBDIVISIONS

a. 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.
b. After the ten (10) year period following the line extension, Company shall refund to Customer, the cost of 1,000 feet of extension for each additional Customer connected during the first ten (10) year period directly to the original extension for which the deposit was made.
c. 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.

7. MOBILE HOME LINE EXTENSIONS

a. Company will make line extensions for service to mobile homes in accordance with 807 KAR 5:041, Section 12, and Commission's Orders.
b. Company shall provide, at no cost, a line extension of up to 300 feet to Customer requesting permanent service for a mobile home.
c. 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.
d. 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.
e. 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.
f. No refund will be made except to the original Customer.

8. UNDERGROUND LINE EXTENSIONS

a. General

i. Company will make underground line extensions for service to new residential Customers and subdivisions in accordance with 807 KAR 5:041, Section 21.

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State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND LILNE EXTENSIONS

General (continued)

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 Customer's side of the point of delivery with the exception of Company's meter.
6) In consideration of Customer's underground service, Company shall credit any amounts due under the contract for each service at the rate of $50.00 or Company's average estimated installed cost for an overhead service whichever is greater.
7) Unit charges, where specified herein, are determined from Company's estimate of Company's average unit cost of such construction and the estimated cost differential between underground and overhead distribution systems in representative residential subdivisions.
8) Three phase primary required to supply either individual loads or the local distribution system may be overhead unless Customer chooses underground construction and deposits with Company a non-refundable deposit for the cost differential.

Individual Premises

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

Medium Density Subdivisions

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

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State Regulation and Rates
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Kentucky Utilities Company

Terms and Conditions
Line Extension Plan

8. UNDERGROUND LINE EXTENSIONS T

General (continued) T

ii. 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. T T

iii. 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. T

iv. 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. T

v. Customer will provide, own, operate and maintain all electric facilities on Customer's side of the point of delivery with the exception of Company's meter. T

D

vii. 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. T

viii. 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. T

b. Individual Premises T

Where Customer requests and Company agrees to supply underground service (primary) to an individual premise, Company may require Customer to furnish ditching, conduit, backfill, and transformer pad. Company will then use overhead extension policy requirements. T N N

D

c. Medium Density Subdivisions T

i. 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. T

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Kentucky Utilities Company

P.S.C. No. 18, First Revision of Original Sheet No. 106.4
Cancelling P.S.C. No. 18, Original Sheet No. 106.4

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS (continued)

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 $10.10 per aggregate lot front-foot along all streets contiguous to the lots to be served I 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 $22.09 per aggregate lot front-foot along all streets contiguous to the lots to R 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.

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.

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ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 106.4

Terms and Conditions
Line Extension Plan

8. UNDERGROUND EXTENSIONS T

c. Medium Density Subdivisions (continued) T

ii. Customer shall provide any required trenching and backfilling or at Company's discretion T be required to deposit with Company a non-refundable amount determined by a unit charge of $10.10 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.

iii. Customer may be required to advance to Company's full estimated cost of construction of T an underground electric distribution extension. Where Customer is required to provide trenching and backfilling, advance will be Company's full estimate cost of construction. Where Customer is required to deposit with Company a non-refundable advance in place of trenching and backfilling, advance will be determined by a unit charge of $22.09 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.

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

v. In no case shall the refunds provided for herein exceed the amounts deposited less any T non-refundable charges applicable to the project nor shall any refund be made after a ten (10) year refund period ends.

d. High Density Subdivisions T

i. A high density residential subdivision is defined as building complexes consisting of two T or more buildings each not more than three stories above grade and each designed for five (5) or more family occupancy.
ii. Customer shall provide any required trenching and backfilling or at Company's discretion T 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.
iii. Customer may be required to advance to Company's full estimated cost of construction T of an underground electric distribution extension.

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 106.5

TERMS AND CONDITIONS

Line Extension Plan

High Density Subdivisions (continued)

i. Company shall refund to Customer any amounts due when permanent service is provided by Company to twenty (20%) percent of the family units in Customer's project.
ii. In no case shall the refunds provided for herein exceed the amounts deposited less any non-refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends.

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

I. SPECIAL CASES

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

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Kentucky Utilities Company

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Terms and Conditions
Line Extension Plan

d. High Density Subdivisions (continued) T

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 (10) year refund period ends.

e. Other Underground Subdivisions T
In cases where a particular residential subdivision does not meet the conditions provided for above and where 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.

9. SPECIAL CASES T

a. Where Customer requests service that is seasonal, intermittent, speculative in nature, at voltages of 34.5kV or greater, or where the facilities requested by Customer do not meet the Terms and Conditions outlined in previous sections of LINE EXTENSION PLAN and the anticipated revenues do not justify Company's installing facilities required to meet Customer's needs, Company may request that Customer deposit with Company a refundable amount to justify Company's investment. T
b. Each year for ten (10) years, Company shall refund to Customer, an amount calculated by: T
   i. Adding the sum of Customer's annual base rate monthly electric demand billing for that year to the sum of the annual base rate monthly electric billing of the monthly electric demand billing for that year of any Customer(s), who connects directly to the facilities provided for in this agreement and requiring no further investment by Company T
   ii. times the refundable amount divided by the estimated total ten (10) year base rate electric demand billing required to justify the investment. T
c. 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. T

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TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PURPOSE

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

ENERGY CURTAILMENT PROCEDURE

PRIORITY LEVELS

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

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

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

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

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

D. "Fire Stations", which shall be limited to facilities housing mobile fire-fighting apparatus.

E. "Communication Services", which shall be limited to essential uses required for telephone, telegraph, television, radio and newspaper operations, and operation of state and local emergency services.

F. "Water and Sewage Services", which shall be limited to essential uses required for the supply of water to a community, flood pumping and sewage disposal.

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State Regulation and Rates
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 19, 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 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.

DATE OF ISSUE: September 28, 2018

DATE EFFECTIVE: With Service Rendered
On and After January 4, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 107.1

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

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.

Although, when practical, these types of uses will be given special consideration when implementing the manual load-shedding provisions of this program, any customer may be affected by rotating or unplanned outages and should install emergency generation equipment if continuity of service is essential. Where the emergency is system-wide in nature, consideration will be given to the use of rotating outages as operationally practicable. In case of customers supplied from two utility sources, only one source will be given special consideration. Also, any other customers who, in their opinion, have critical equipment should install emergency generation equipment.

Company maintains lists of customers with life support equipment and other critical needs for the purpose of curtailments and service restorations. Company, lacking knowledge of changes that may occur at any time in customer's equipment, operation, and backup resources, does not assume the responsibility of identifying customers with priority needs. It shall, therefore, be the customer's responsibility to notify Company if Customer has critical needs.

II. Critical Commercial and Industrial Uses -- Except as described in Section III below, these uses shall include commercial or industrial operations requiring regimented shutdowns to prevent conditions hazardous to the general population, and to energy utilities and their support facilities critical to the production, transportation, and distribution of service to the general population. Company shall maintain a list of such customers for the purpose of curtailments and service restoration.

III. Residential Use -- The priority of residential use during certain weather conditions (for example severe winter weather) will receive precedence over critical commercial and industrial uses. The availability of Company service personnel and the circumstances associated with the outage will also be considered in the restoration of service.

IV. Non-critical commercial and industrial uses.

V. Nonessential Uses -- The following and similar types of uses of electric energy shall be considered nonessential for all customers:

DATE OF ISSUE: July 7, 2017

DATE EFFECTIVE: January 4, 2013

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

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

Kentucky Utilities Company

P.S.C. No. 19, Original Sheet No. 107.1

Terms and Conditions
Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 107.2

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

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.

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.

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Kentucky Utilities Company

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Terms and Conditions

Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

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Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 107.3

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

CURTAILMENT PROCEDURES (continued)

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.

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State Regulation and Rates
Lexington, Kentucky

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Terms and Conditions
Energy Curtailment and Service Restoration Procedures

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Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(5)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A statement that notice has been given in compliance with Section 17 of this administrative regulation with a copy of the notice.

Response:

Customer notice has been given in compliance with 807 KAR 5:001, Section 17. Notice given pursuant to 807 KAR 5:001, Section 17 satisfies the requirements of 807 KAR 5:051, Section 2. See attached Certificate of Notice.

The Commission granted the request of KU and Louisville Gas and Electric Company ("LG&E") to publish an abbreviated newspaper customer notice (see attached).[1] Also, KU and LG&E are required to post the full customer notice (see attached) in each public library located in the service territories.[2]

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[1] *In the Matter of: Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for a Declaratory Order Establishing the Form of Notice and Number of Copies of Certain Documents Filed in Support of Upcoming Applications for Rate Adjustments*, Case No. 2018-00250, Order (Ky. PSC August 31, 2018), Ordering Paragraph No. 1.
[2] *Id.*

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	))))	**CASE NO. 2018-00294**

CERTIFICATE OF NOTICE

Pursuant to the Kentucky Public Service Commission's Regulation 807 KAR 5:001, Section 16(1)(b)(5), I hereby certify that I am Robert M. Conroy, Vice President, State Regulation and Rates, for Kentucky Utilities Company ("KU" or "Company"), a utility furnishing retail electric service within the Commonwealth of Kentucky which, on the 28th day of September, 2018, filed an application with the Kentucky Public Service Commission ("Commission") for the approval of an adjustment of the electric rates, terms, conditions and tariffs of KU, and that notice to the public of the filing of the application is being given in all respects as required by the Commission's Order in Case No. 2018-00250,[1] as follows:

I 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 19th day of September, 2018, 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 the week ending September 28, 2018, an abbreviated notice in conformity with the Commission's Order of August 31, 2018, in Case No. 2018-00250 of the filing of KU's

[1] *In the Matter of: Application of Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Establishing the Form of Notice and Number of Copies of Certain Documents to be Filed in Support of their Upcoming Applications for Rate Adjustment*, Case No. 2018-00250, Order (Ky. PSC Aug. 31, 2018).

application. A copy of said notice is attached hereto as Exhibit A. A list of newspapers of general circulation throughout the Commonwealth of Kentucky in which KU's customers affected reside is attached hereto as Exhibit B. A certificate of publication of said notice will be furnished to the Kentucky Public Service Commission upon completion pursuant to 807 KAR 5:001, Section 17(3)(b).

On the 24th day of September, 2018, the full customer notice to the public, a copy of which is attached hereto as Exhibit C, was delivered for exhibition and public inspection at the offices and places of business of the Company in the territory affected thereby, to-wit, at the following places:

Barlow	Maysville
Campbellsville	Middlesboro
Carrollton	Morehead
Danville	Morganfield
Earlington	Mt. Sterling
Eddyville	Paris
Elizabethtown	Richmond
Georgetown	Shelbyville
Greenville	Somerset
Harlan	Versailles
Lexington	Winchester
London	

and will be kept open to public inspection at said offices and places of business in conformity with the Commission's Order in Case No. 2018-00250. Also in accordance with that Order, on the 21st day of September, 2018, KU sent by certified mail to each public library, located within KU's service territory a copy of the full customer notice and a request to post it in a public location. A list of those libraries is attached hereto as Exhibit D.

Also beginning on 24th day of September, 2018, KU posted on its website a copy of the full customer notice that 807 KAR 5:001, Section 17 requires and a hyperlink to the location on the Commission's website where the case documents and tariff filings are available. Beginning on 28th day of September, 2018, KU posted on its website a complete copy of KU's application in this case. KU's Application filed with the Commission on the 28th day of September, 2018, includes the customer notice as a separate document labeled "Customer Notice of Rate Adjustment."

In addition, beginning on the 19th day of September, 2018, KU issued press advisories to all known news media organizations who cover the areas within its certified territory advising of the filing of its application and including a hyperlink to the location on KU's and the Commission's websites where case documents and tariff filings will be available.

Beginning on the 28th day of September, 2018, KU began including a general statement explaining the application in this case with the bills for all Kentucky retail customers during the course of their regular monthly billing cycle. An accurate copy of this general statement is attached as Exhibit E. Both the notice being published in newspapers and the bill inserts being sent to customers include the web address to the online posting.

Also beginning on 28th day of September, 2018, KU provided notice by certified mail to special contract customers and state, local, and federal governmental units and educational institutions, such as public and private colleges eligible to affix attachments to Company structures.

Given under my hand this 28th day of September, 2018.

Robert M. Conroy
Vice President, State Regulation and Rates
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of September, 2018.

_______________(SEAL)
Notary Public

My Commission Expires:
Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

Exhibit A

Notice of the Filing – Abbreviated

CUSTOMER NOTICE OF RATE ADJUSTMENT

PLEASE TAKE NOTICE that, in a September 28, 2018, Application, Kentucky Utilities Company ("KU") is seeking approval by the Kentucky Public Service Commission of an adjustment of its electric rates and charges to become effective on and after November 1, 2018.

KU CURRENT AND PROPOSED RESIDENTIAL ELECTRIC RATES

Residential Service – Rate RS

	Current	Proposed
Basic Service Charge per Month:	$12.25	
Basic Service Charge per Day:		$ 0.53
Plus an Energy Charge per kWh:	$ 0.09047	
Infrastructure:		$ 0.06318
Variable:		$ 0.03234
Total:		$ 0.09552

Residential Time-of-Day Energy Service - Rate RTOD-Energy

	Current	Proposed
Basic Service Charge per Month:	$12.25	
Basic Service Charge per Day:		$ 0.53
Plus an Energy Charge per kWh:		
Off-Peak Hours	$ 0.05892	
Off-Peak Hours (Infrastructure):		$ 0.02658
Off-Peak Hours (Variable):		$ 0.03234
Off-Peak Hours (Total):		$ 0.05892
On-Peak Hours	$ 0.27615	
On-Peak Hours (Infrastructure):		$ 0.28583
On-Peak Hours (Variable):		$ 0.03234
On-Peak Hours (Total):		$ 0.31817

Residential Time-of-Day Demand Service - Rate RTOD-Demand

	Current	Proposed
Basic Service Charge per Month:	$12.25	
Basic Service Charge per Day:		$0.53
Plus an Energy Charge per kWh:	$ 0.04478	
Plus an Energy Charge per kWh (Infrastructure):		$ 0.01244
Plus an Energy Charge per kWh (Variable):		$ 0.03234
Plus an Energy Charge per kWh (Total):		$ 0.04478
Plus a Demand Charge per kW:		
Base Hours	$ 3.44	$ 3.44
Peak Hours	$ 7.87	$ 8.90

KU is also proposing changes to the rates for other customer classes. These customer classes and the changes in their associated annual revenue changes are listed in the tables shown below. KU is also proposing changes in the text of some of its rate schedules and other tariff provisions, including substantive changes in its terms and conditions for electric service and miscellaneous charges. KU's proposed rates reflect a proposed annual increase in electric revenues of approximately 7.11%.

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 are as follows:

Electric Rate Class	**Average Usage (kWh)**	**Annual $ Increase**	**Annual % Increase**	**Monthly Bill $ Increase**	**Monthly Bill % Increase**
Residential	1,139	50,433,651	8.10	9.63	8.10
Residential Time-of-Day Energy	1,142	6,406	8.11	8.68	8.11
General Service	1,717	15,621,049	6.61	15.41	6.61
All Electric School	19,744	852,252	6.60	127.28	6.61
Power Service	34,810	12,186,004	6.61	217.19	6.61
Time-of-Day Secondary	208,133	8,381,858	6.11	949.03	6.11
Time-of-Day Primary	1,294,965	15,925,393	6.11	5,117.42	6.11
Retail Transmission	4,908,868	5,347,588	6.12	17,825.29	6.12
Fluctuating Load Service	51,873,999	2,077,780	6.12	173,148.31	6.12
Outdoor Lights	59	2,090,440	6.61	1.00	6.59
Lighting Energy	3,573	0.00	0.00	0.00	0.00
Traffic Energy	171	(396.00)	(0.21)	(0.04)	(0.20)
PSA	N/A	0.00	0.00	0.00	0.00
Rider – CSR	N/A	0.00	0.00	0.00	0.00
Outdoor Sports Lighting – Pilot Program	5,204	3,921	6.62	54.45	6.62

The monthly residential electric bill increase due to the proposed electric base rates will be 8.1 percent, or approximately $9.63, for a customer using 1,139 kWh of electricity (the average monthly consumption of a KU residential customer). KU is proposing to withdraw Adjustment Clause TCJA from service and cancelling the associated billing credits effective when new base rates change. When the TCJA Surcredit is cancelled when new base rates take effect, the total monthly residential electric bill increase will be 11.7%, or approximately $13.47, for a customer using 1,139 kWh of electricity.

KU is proposing numerous revisions to the rates, terms and conditions for service under Pole and Structure Attachment Charges – Rate PSA, including expanding the availability of the schedule to internal communication network facilities of governmental units and educational institutions. If approved, the rates terms and conditions for attaching communication network facilities of such governmental units and educational institutions will be subject to Rate Schedule PSA.

Other Charges

KU is proposing the following revisions to other charges in the tariff:

Other Charges	Current Charge	Proposed Charge
Returned Payment Charge	$10.00	$3.00
Meter Pulse Charge	$15.00	$25.00
Redundant Capacity - Secondary	$1.04	$1.16
Redundant Capacity - Primary	$0.86	$0.99
EVSE – Single Charger	$182.31	$134.34
EVSE – Dual Charger	$306.10	$196.64
EVSE-R – Single Charger	$131.41	$123.99
EVSE-R – Dual Charger	$204.31	$175.95
EVC – Charge per Hour for First Two Hours	$2.84	$0.75
EVC – Charge per Hour for Every Hour After First Two Hours	$2.84	$1.00
Solar Share Program Rider	$6.27	$5.68
Excess Facilities – w/ no CIAC	1.24%	1.20%
Excess Facilities – w/ CIAC	0.48%	0.47%
TS – Temporary-to-Permanent	100%	15%
TS – Seasonal	100%	100%

A detailed notice of all proposed revisions and a complete copy of the proposed tariffs containing the proposed text changes, terms and conditions and rates may be obtained by submitting a written request by e-mail to myaccount@lge-ku.com or by mail to Kentucky Utilities Company, ATTN: Rates Department, 220 West Main Street, Louisville, Kentucky, 40202, or by visiting KU's website at www.lge-ku.com. A copy of the full customer notice required by 807 KAR 5:001 Section 17 is posted and may be viewed in each public library located within KU's service territory or at the KU offices where bills are paid.

A person may examine KU's application at the offices of KU located at 100 Quality Street, Lexington, Kentucky or at the other KU business offices, and at KU's website at www.lge-ku.com. A person may also examine this application at the Public Service Commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or may view and download the through the Commission's Web site at http://psc.ky.gov.

Comments regarding the application may be submitted to the Public Service Commission by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, or by sending an email to the Commission's Public Information Officer at psc.info@ky.gov. All comments should reference Case No. 2018-00294.

The rates contained in this notice are the rates proposed by KU, but the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice. A person may submit a timely written request for intervention to the Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party. If the commission does not receive a written request for intervention within thirty (30) days of initial publication or mailing of the notice, the commission may take final action on the application.

Kentucky Utilities Company
c/o LG&E and KU Energy LLC
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40232
1-800-981-0600

Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602
502-564-3940

Exhibit B

Listing of Newspapers Publishing Notice

List of Newspapers in KU Territory
Columbia Adair Progress
Lawrenceburg Anderson News
Wickliffe Advance Yeoman
Glasgow Daily Times
Cave City Barren Co Progress
Owingsville Bath Co Outlook
Middlesboro Daily News
Pineville Sun
Paris Bourbon Citizen
The Advocate Messenger
Brooksville Bracken Co News
Shepherdsville Pioneer News
Princeton Times Leader
Florence Boone Co
Bardwell Carlisle Co News
Bardwell Carlisle Weekly
Carrollton News Democrat
Liberty Casey Co News
Hopkinsville KY New Era
Winchester Sun
Manchester Enterprise
Marion Crittenden Press
Owensboro Messenger Inquirer
Brownsville Edmonson News
Irvine Citizen Voice & Times
Irvine Estill Tribune
Lexington Herald Leader
Flemingsburg Gazette
Frankfort State Journal
The Current-Fulton Leader
Warsaw Gallatin Co News
Lancaster Central Record
Williamstown Grant Co New
Leitchfield News Gazette
Leitchfield The Record
Greensburg Record Herald
Elizabethtown News Enterprise
Harlan Enterprise
Cumberland Tri City News
Cynthiana Democrat
Munfordville Hart Co News
Henderson Gleaner
New Castle Henry Co Local
Hickman Co Times
Madisonville Messenger

Dawson Springs Progress
Louisville Courier Journal
Nicholasville Jessamine Journal
Barbourville Mountain Advocate
Hodgenville Larue Herald
London Sentinel Echo
Beattyville Enterprise
Beattyville Three Forks Tradition
Stanford Interior Journal
Smithland Livingston Ledger
Eddyville Herald Ledger
Berea Citizen
Richmond Register
Lebanon Enterprise
Maysville Ledger Independent
Paducah Sun
Whitley City McCreary Voice
Calhoun McLean Co News
Harrodsburg Herald
Mt. Sterling Advocate
Central City Leader News
Central City Times Argus
Bardstown KY Standard
Carlisle Mercury
Hartford Ohio Co Times
LaGrange Oldham Era
Owenton News Herald
Falmouth Outlook
Commonwealth Journal
Robertson Co News
Mt. Vernon Signal
Morehead News
Russell Springs Times Journal
Georgetown News Graphic
Shelbyville Sentinel News
Taylorsville Spencer Magnet
Campbellsville Central KY News
Bedford Trimble Banner
Morganfield Union Co Advocate
Sturgis News
Springfield Sun
Providence Journal Enterprise
Sebree Banner
Corbin Times Tribune
Williamsburg News Journal
Versailles Woodford Sun

Exhibit C

Notice of the Filing – Full Notice

CUSTOMER NOTICE OF RATE ADJUSTMENT

Notice is hereby given that, in a September 28, 2018, Application, Kentucky Utilities Company is seeking approval by the Public Service Commission of an adjustment of electric rates and charges proposed to become effective on and after November 1, 2018.

KU CURRENT AND PROPOSED ELECTRIC RATES

Residential Service - Rate RS

Rate:

	Current	Proposed
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Basic Service Charge per Day:		$0.53
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Infrastructure		$0.06318
Variable		$0.03234
Total		$0.09552

Adjustment Clauses:

Current

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
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
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

Proposed

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
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Home Energy Assistance Program	Sheet No. 92
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Late Payment Charge:

Current

If full payment is not received by the due date of the bill, a 3% 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.

Proposed

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges. 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.

Beginning May 1, 2019, Residential Service Customers in good standing by not having been assessed a Late Payment Charge for the previous eleven (11) months have the option of waiving one (1) late payment charge upon request. This option may only be used once every twelve (12) months as long as the Customer remains in good standing.

Residential Time-of-Day Energy Service - Rate RTOD-Energy

Rate:

	Current	Proposed
Basic Service Charge per Month:	$12.25	
Basic Service Charge per Day:		$0.53
Plus an Energy Charge per kWh:		
Off-Peak Hours	$ 0.05892	
Off-Peak Hours (Infrastructure):		$0.02658
Off-Peak Hours (Variable):		$0.03234
Off-Peak Hours (Total):		$0.05892
On-Peak Hours	$ 0.27615	
On-Peak Hours (Infrastructure):		$0.28583
On-Peak Hours (Variable):		$0.03234
On-Peak Hours (Total):		$0.31817

Adjustment Clauses:

Current

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
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
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

Proposed

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
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Home Energy Assistance Program	Sheet No. 92
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Rating Periods:

Current

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 April through October

	Off-Peak	On-Peak
Weekdays	5 PM - 1 PM	1 PM - 5 PM
Weekends	All Hours	

All Other Months of November continuously through March

	Off-Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM - 11 AM
Weekends	All Hours	

Proposed

The rating periods are established in Eastern Standard Time year-round by season for weekdays and weekends throughout Company's service territory, and shall be as follows:

Summer Months of April through October

	Off-Peak	On-Peak
Weekdays	5 PM - 1 PM	1 PM - 5 PM
Weekends	All Hours	

All Other Months of November continuously through March

	Off-Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM - 11 AM
Weekends	All Hours	

If a legal holiday falls on a weekday, it will be considered a weekday.

Late Payment Charge:

Current

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

Proposed

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

Beginning May 1, 2019, RTOD-Energy Customers in good standing by not having been assessed a Late Payment Charge for the previous eleven (11) months have the option of waiving one (1) late payment charge upon request. This option may only be used once every twelve (12) months as long as the Customer remains in good standing.

Residential Time-of-Day Demand Service - Rate RTOD-Demand

Rate:

Current

Basic Service Charge per Month:	$12.25
Plus an Energy Charge per kWh:	$0.04478
Plus a Demand Charge per kW:	
Base Hours	$3.44
Peak Hours	$7.87

Proposed

Basic Service Charge per Day:	$0.53
Plus an Energy Charge per kWh (Infrastructure):	$0.01244
Plus an Energy Charge per kWh (Variable):	$0.03234
Plus an Energy Charge per kWh (Total):	$0.04478
Plus a Demand Charge per kW:	
Base Hours	$3.44
Peak Hours	$8.90

Adjustment Clauses:

Current

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
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
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

Proposed

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
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Home Energy Assistance Program	Sheet No. 92
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Rating Periods:

Current

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 April through October

	Off-Peak	On-Peak
Weekdays	All Hours	1 PM - 5 PM
Weekends	All Hours	

All Other Months of November continuously through March

	Off-Peak	On-Peak
Weekdays	All Hours	7 AM - 11 AM
Weekends	All Hours	

Proposed

The rating periods are established in Eastern Standard Time year-round by season for weekdays and weekends throughout Company's service territory, and shall be as follows:

Summer Months of April through October

	Off-Peak	On-Peak
Weekdays	All Hours	1 PM - 5 PM
Weekends	All Hours	

All Other Months of November continuously through March

	Off-Peak	On-Peak
Weekdays	All Hours	7 AM - 11 AM
Weekends	All Hours	

If a legal holiday falls on a weekday, it will be considered a weekday.

Late Payment Charge:

Current

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

Proposed

If full payment is not received by the due date of the bill, a 3% late payment charge will be assessed on the current month's charges.

Beginning May 1, 2019, RTOD-Demand Customers in good standing by not having been assessed a Late Payment Charge for the previous eleven (11) months have the option of waiving one (1) late payment charge upon request. This option may only be used once every twelve (12) months as long as the Customer remains in good standing.

Volunteer Fire Department Service - Rate VFD

Rate:

	Current	**Proposed**
Basic Service Charge per Month:	$12.25	
Basic Service Charge per Day:		$0.53
Plus an Energy Charge per kWh:	$0.09047	
Infrastructure		$0.06318
Variable		$0.03234
Total		$0.09552

Adjustment Clauses:

Current

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
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Proposed

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
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

General Service – Rate GS

Rate:

Single Phase	**Current**	**Proposed**
Basic Service Charge per Month	$31.50	
Basic Service Charge per Day:		$1.04
Plus an Energy Charge per kWh	$0.10490	
Infrastructure		$0.08108
Variable		$0.03271
Total		$0.11379
Three Phase	**Current**	**Proposed**
Basic Service Charge per Month	$50.40	
Basic Service Charge per Day:		$1.66
Plus an Energy Charge per kWh	$0.10490	
Infrastructure		$0.08108
Variable		$0.03271
Total		$0.11379

Adjustment Clauses:

Current

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
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Proposed

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
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

All Electric School – Rate AES

Rate:

Single Phase	**Current**	**Proposed**
Basic Service Charge per Month	$85.00	
Basic Service Charge per Day:		$2.80
Plus an Energy Charge per kWh	$0.08244	
Infrastructure		$0.05637
Variable		$0.03251
Total		$0.08888
Three Phase		
Basic Service Charge per Month:	$140.00	
Basic Service Charge per Day:		$ 4.60
Plus an Energy Charge per kWh	$0.08244	
Infrastructure		$0.05637
Variable		$0.03251
Total		$0.08888

Adjustment Clauses:

Current

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
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Proposed

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
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Power Service – Rate PS

Rate:

Secondary Service	**Current**	**Proposed**
Basic Service Charge per Month	$90.00	
Basic Service Charge per Day		$2.96
Plus an Energy Charge per kWh	$0.03270	$0.03270
Plus a Demand Charge per kW per month of billing demand		
Summer Rate (May through September)	$21.03	$23.22
Winter Rate (All Other Months)	$18.81	$20.78

Primary Service	**Current**	**Proposed**
Basic Service Charge per Month	$240.00	
Basic Service Charge per Day		$7.89
Plus an Energy Charge per kWh	$0.03171	$0.03209
Plus a Demand Charge per kW per month of billing demand		
Summer Rate (May through September)	$21.21	$23.32
Winter Rate (All Other Months)	$19.02	$20.91

Adjustment Clauses:

Current

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
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Proposed

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
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Time-of-Day Secondary Service - Rate TODS

Availability:

Current

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

Proposed

Available for secondary service to Customers whose twelve (12) month-average monthly minimum loads exceed 250 kVA, and whose twelve (12) month-average monthly maximum loads do not exceed 5,000 kVA.

Rate:

	Current	**Proposed**
Basic Service Charge per Month	$200.00	
Basic Service Charge per Day		$6.58
Plus an Energy Charge per kWh	$0.03229	$0.03248
Plus a Maximum Load Charge per kW per month		
Peak Demand Period	$8.09	
Intermediate Demand Period	$6.41	
Base Demand Period	$3.03	

Plus a Maximum Load Charge per kVA per month

Peak Demand Period	$8.17
Intermediate Demand Period	$6.47
Base Demand Period	$2.65

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

the monthly billing demand for the Base Demand Period is the greater of:
1. the maximum measured load in the current billing period but not less than 250 kVA, or
2. the highest measured load in the preceding eleven (11) monthly billing periods, or
3. the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Adjustment Clauses:
Current
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
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Proposed
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
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Rating Periods:

Current

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		

Proposed

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		

If a legal holiday falls on a weekday, it will be considered a weekday.

Determination of Maximum Load:

Current

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

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

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

Proposed

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

Time-of-Day Primary Service - Rate TODP

Rate:

	Current	**Proposed**
Basic Service Charge per Month	$330.00	
Basic Service Charge per Day		$10.84
Plus an Energy Charge per kWh	$0.03136	$0.03161
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$6.71	$7.79
Intermediate Demand Period	$5.31	$6.16
Base Demand Period	$3.03	$2.87

Adjustment Clauses:

<u>Current</u>

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
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

<u>Proposed</u>

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
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Rating Periods:

<u>Current</u>

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:

<u>Summer peak months of May through September</u>

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

<u>All other months of October continuously through April</u>

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

<u>Proposed</u>

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:

<u>Summer peak months of May through September</u>

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

<u>All other months of October continuously through April</u>

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

If a legal holiday falls on a weekday, it will be considered a weekday.

Retail Transmission Service - Rate RTS

Rate:

	Current	Proposed
Basic Service Charge per Month	$1,500.00	
Basic Service Charge per Day		$49.28
Plus an Energy Charge per kWh	$0.03058	$0.03101
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$6.55	$7.59
Intermediate Demand Period	$5.18	$6.01
Base Demand Period	$2.23	$1.97

Adjustment Clauses:

Current

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
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Proposed

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
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Rating Periods:

Current

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		

Proposed
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		

If a legal holiday falls on a weekday, it will be considered a weekday.

Fluctuating Load Service – Rate FLS

Rate:

Primary Service	**Current**	**Proposed**
Basic Service Charge per Month	$330.00	
Basic Service Charge per Day		$10.84
Plus an Energy Charge per kWh	$0.03136	$0.03161
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$6.03	$7.40
Intermediate Demand Period	$4.60	$5.80
Base Demand Period	$2.57	$2.68
Transmission Service	**Current**	**Proposed**
Basic Service Charge per Month	$1,500.00	
Basic Service Charge per Day		$ 49.28
Plus an Energy Charge per kWh	$0.03036	$ 0.03101
Plus a Maximum Load Charge per kVA per month		
Peak Demand Period	$3.37	$3.88
Intermediate Demand Period	$2.41	$2.76
Base Demand Period	$1.65	$1.65

Adjustment Clauses:

Current
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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Proposed
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
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Rating Periods:
Current
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		

Proposed
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		

If a legal holiday falls on a weekday, it will be considered a weekday.

Lighting Service - Rate LS

	Rate Per Light Per Month	
OVERHEAD SERVICE	**Current**	**Proposed**
High Pressure Sodium		
462 Cobra Head – 5,800 Lumen – Fixture Only	$10.10	Move to RLS
472 Cobra Head – 5,800 Lumen – Ornamental	$13.77	Move to RLS
463 Cobra Head – 9,500 Lumen – Fixture Only	$10.49	Move to RLS
473 Cobra Head – 9,500 Lumen – Ornamental	$14.36	Move to RLS
464 Cobra Head – 22,000 Lumen – Fixture Only*	$16.28	Move to RLS
474 Cobra Head – 22,000 Lumen – Ornamental*	$20.43	Move to RLS
465 Cobra Head – 50,000 Lumen – Fixture Only*	$25.75	Move to RLS
475 Cobra Head – 50,000 Lumen – Ornamental*	$28.53	Move to RLS
487 Directional – 9,500 Lumen – Fixture Only	$10.33	Move to RLS
488 Directional – 22,000 Lumen – Fixture Only*	$15.62	Move to RLS

High Pressure Sodium (continued)	Rate Per Light Per Month Current	Proposed
489 Directional – 50,000 Lumen – Fixture Only*	$22.09	Move to RLS
428 Open Bottom – 9,500 Lumen – Fixture Only	$ 9.01	Move to RLS
Metal Halide		
451 Directional – 32,000 Lumen – Fixture Only	$23.07	Move to RLS
Light Emitting Diode (LED)		
390 Cobra Head – 6K-8.2K Lumen Range – Fixture Only	$15.88	$10.23
391 Cobra Head – 13K-16.5K Lumen Range – Fixture Only*	$18.60	$12.34
392 Cobra Head – 22K-29K Lumen Range – Fixture Only*	$27.95	$15.67
393 Open Bottom – 4.5K-6K Lumen Range – Fixture Only	$10.71	$8.80
KC1 Cobra Head – 2.5K-4K Lumen Range – Fixture Only	New	$8.95
KF1 Directional – 4.5K-6K Lumen Range – Fixture Only	New	$11.65
KF2 Directional – 14K-17.5K Lumen Range – Fixture Only	New	$13.51
KF3 Directional – 22K-28K Lumen Range – Fixture Only	New	$15.96
KF4 Directional – 35K-50K Lumen Range – Fixture Only	New	$22.87

UNDERGROUND SERVICE	Rate Per Light Per Month Current	Proposed
High Pressure Sodium		
467 Colonial – 5,800 Lumen – Decorative	$12.84	Move to RLS
468 Colonial – 9,500 Lumen – Decorative	$13.07	Move to RLS
401 Acorn – 5,800 Lumen – Smooth Pole	$17.43	Move to RLS
411 Acorn – 5,800 Lumen – Fluted Pole	$24.76	Move to RLS
420 Acorn – 9,500 Lumen – Smooth Pole	$17.79	Move to RLS
430 Acorn – 9,500 Lumen – Fluted Pole	$25.25	Move to RLS
414 Victorian 5,800 Lumen – Fluted Pole	$34.32	$36.75
415 Victorian 9,500 Lumen – Fluted Pole	$34.53	$36.98
476 Contemporary – 5,800 Lumen – Fixture/Pole	$19.60	Move to RLS
492 Contemporary – 5,800 Lumen – 2nd Fixture	$17.36	Move to RLS
477 Contemporary – 9,500 Lumen – Fixture/Pole	$24.09	Move to RLS
497 Contemporary – 9,500 Lumen – 2nd Fixture	$17.14	Move to RLS
478 Contemporary– 22,000 Lumen – Fixture/Pole*	$31.05	Move to RLS
498 Contemporary– 22,000 Lumen – 2nd Fixture*	$20.04	Move to RLS
479 Contemporary– 50,000 Lumen – Fixture/Pole*	$38.26	Move to RLS
499 Contemporary– 50,000 Lumen – 2nd Fixture*	$24.29	Move to RLS
300 Dark Sky – 4,000 Lumen	$25.05	Move to RLS
301 Dark Sky – 9,500 Lumen	$26.13	Move to RLS

Metal Halide	Current	Proposed
491 Contemporary – 32,000 Lumen – Fixture Only	$24.95	Move to RLS
495 Contemporary – 32,000 Lumen – Smooth Pole	$39.14	Move to RLS
Light Emitting Diode (LED)		
KC2 Cobra Head – 2.5K-4K Lumen Range – Fixture	New	$4.13
396 Cobra Head – 6K-8.2K Lumen Range – Fixture	$36.40	$5.40
397 Cobra Head – 13K-16.5K Lumen Range – Fixture	$39.12	$7.52
398 Cobra Head – 22K-29K Lumen Range – Fixture	$48.46	$10.85
399 Colonial, 4Sided – 4K-7K Lumen Range – Fixture	$38.22	$7.65
KA1 Acorn, 4K-7k Lumen Range – Fixture	New	$9.12
KN1 Contemporary, 4K-7K Lumen Range – Fixture	New	$7.09

Light Emitting Diode (LED) (continued)	Current	Proposed
KN2 Contemporary, 8K-11K Lumen Range - Fixture	New	$8.25
KN3 Contemporary, 13.5K-16.5K Lumen Range - Fixture	New	$10.03
KN4 Contemporary, 21K-28K Lumen Range - Fixture	New	$14.55
KN5 Contemporary, 45K-50K Lumen Range - Fixture	New	$21.95
KF5 Directional, 4.5K-6K Lumen Range - Fixture	New	$8.45
KF6 Directional, 14K-17.5K Lumen Range - Fixture	New	$10.31
KF7 Directional, 22K-28K Lumen Range - Fixture	New	$12.75
KF8 Directional, 35K-50K Lumen Range - Fixture	New	$19.67
Pole Charges		
PK1 Cobra	New	$12.49
PK2 Contemporary	New	$12.00
PK3 Post-Top – Decorative Smooth	New	$8.25
PK4 Post-Top – Historic Fluted	New	$15.48

NEW
Conversion Fee
Customer will be required to pay a monthly conversion fee for 60 months if Customer requests to change current functioning non-LED fixture to an LED fixture. This conversion fee represents the remaining book value of the current working non-LED fixture.
Conversion Fee: $6.12 per month for 60 months

Adjustment Clauses:
Current
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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Proposed
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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Terms and Conditions:
Current

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.

Proposed

6. If Customer requests the removal of an existing lighting system, including, but not limited to, fixtures, poles, or other supporting facilities, Customer agrees to pay to Company its cost of labor to remove existing facilities. Customer will be required to pay Conversion Fee if Customer requests installation of LED replacement within five (5) years.

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.

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

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

Restricted Lighting Service - Rate RLS

	Rate Per Light Per Month	
OVERHEAD SERVICE	**Current**	**Proposed**
High Pressure Sodium		
461 Cobra Head – 4,000 Lumen – Fixture Only	$ 9.03	$9.67
471 Cobra Head – 4,000 Lumen – Fixture & Pole	$12.35	$13.23
462 Cobra Head – 5,800 Lumen – Fixture Only	Moved from LS	$10.82
472 Cobra Head – 5,800 Lumen – Fixture & Pole	Moved from LS	$14.75
463 Cobra Head – 9,500 Lumen – Fixture Only	Moved from LS	$11.23
473 Cobra Head – 9,500 Lumen – Fixture & Pole	Moved from LS	$15.38
464 Cobra Head – 22,000 Lumen – Fixture Only	Moved from LS	$17.43
474 Cobra Head – 22,000 Lumen – Fixture & Pole	Moved from LS	$21.88
465 Cobra Head – 50,000 Lumen – Fixture Only	Moved from LS	$27.58
475 Cobra Head – 50,000 Lumen – Fixture & Pole	Moved from LS	$30.55
409 Cobra Head – 50,000 Lumen – Fixture Only*	$14.21	$15.22
426 Open Bottom – 5,800 Lumen – Fixture Only	$ 8.78	$9.40
428 Open Bottom – 9,500 Lumen – Fixture Only	Moved from LS	$9.65
487 Directional – 9,500 Lumen – Fixture Only	Moved from LS	$11.06
488 Directional – 22,000 Lumen – Fixture Only	Moved from LS	$16.73
489 Directional – 50,000 Lumen – Fixture Only	Moved from LS	$23.66

	Rate Per Light Per Month	
Metal Halide	**Current**	**Proposed**
450 Directional – 12,000 Lumen – Fixture Only	$16.47	$17.64
454 Directional – 12,000 Lumen – Flood Fixture & Pole	$21.23	$22.74
455 Directional – 32,000 Lumen – Flood Fixture & Pole*	$27.83	$29.80
452 Directional – 107,800 Lumen – Fixture Only*	$48.09	$51.50
459 Directional – 107,800 Lumen – Flood Fixture & Pole*	$52.84	$56.59
451 Directional – 32,000 Lumen – Fixture Only	Moved from LS	$24.71
Mercury Vapor		
446 Cobra Head – 7,000 Lumen – Fixture Only	$10.93	$11.71
456 Cobra Head – 7,000 Lumen – Fixture & Pole	$13.43	$14.38
447 Cobra Head – 10,000 Lumen – Fixture Only	$12.90	$13.82
457 Cobra Head – 10,000 Lumen – Fixture & Pole	$15.12	$16.19
448 Cobra Head – 20,000 Lumen – Fixture Only	$14.56	$15.59

Mercury Vapor (continued)	Rate Per Light Per Month Current	Proposed
458 Cobra Head – 20,000 Lumen – Fixture & Pole	$17.04	$18.25
404 Open Bottom – 7,000 Lumen – Fixture Only	$11.96	$12.81
Incandescent		
421 Tear Drop – 1,000 Lumen – Fixture Only	$ 3.81	$4.09
422 Tear Drop – 2,500 Lumen – Fixture Only	$ 5.05	$5.41
424 Tear Drop – 4,000 Lumen – Fixture Only	$ 7.51	$8.03
425 Tear Drop – 6,000 Lumen – Fixture Only	$10.02	$10.74

UNDERGROUND SERVICE	Rate Per Light Per Month Current	Proposed
Metal Halide		
460 Direct – 12,000 Lumen – Flood Fixture & Pole	$31.57	$33.81
469 Direct – 32,000 Lumen – Flood Fixture & Pole*	$37.27	$39.91
470 Direct – 107,800 Lumen – Flood Fixture & Pole*	$62.05	$66.45
490 Contemporary – 12,000 Lumen – Fixture Only	$17.79	$19.05
491 Contemporary – 32,000 Lumen – Fixture Only	Moved from LS	$26.72
494 Contemporary – 12,000 Lumen – Smooth Pole	$31.76	$34.01
493 Contemporary – 107,800 Lumen – Fixture Only*	$51.71	$55.38
495 Contemporary – 32,000 Lumen – Contemporary Pole	Moved from LS	$41.92
496 Contemporary – 107,800 Lumen – Smooth Pole*	$65.67	$70.33
High Pressure Sodium		
440 Acorn – 4,000 Lumen – Flood Fixture & Pole	$15.88	$17.02
410 Acorn – 4,000 Lumen – Fluted Pole	$23.33	$24.98
401 Acorn – 5,800 Lumen – Smooth Pole	Moved from LS	$18.67
411 Acorn – 5,800 Lumen – Fluted Pole	Moved from LS	$26.52
420 Acorn – 9,500 Lumen – Smooth Pole	Moved from LS	$19.05
430 Acorn – 9,500 Lumen – Fluted Pole	Moved from LS	$27.04
466 Colonial – 4,000 Lumen – Smooth Pole	$11.37	$12.18
412 Coach – 5,800 Lumen – Smooth Pole	$34.31	$36.74
413 Coach – 9,500 Lumen – Smooth Pole	$34.54	$36.99
467 Colonial – 5,800 Lumen – Smooth Pole	Moved from LS	$13.75
468 Colonial – 9,500 Lumen – Smooth Pole	Moved from LS	$14.00
492 Contemporary – 5,800 Lumen – Fixture Only	Moved from LS	$18.59
476 Contemporary – 5,800 Lumen – Contemporary Pole	Moved from LS	$20.99
497 Contemporary – 9,500 Lumen – Fixture Only	Moved from LS	$18.36
477 Contemporary – 9,500 Lumen – Contemporary Pole	Moved from LS	$25.80
498 Contemporary – 22,000 Lumen – Fixture Only	Moved from LS	$21.46
478 Contemporary – 22,000 Lumen – Contemporary Pole	Moved from LS	$33.25
499 Contemporary – 50,000 Lumen – Fixture Only	Moved from LS	$26.01
479 Contemporary – 50,000 Lumen – Contemporary Pole	Moved from LS	$40.97
300 Dark Sky – 4,000 Lumen – Smooth Pole	Moved from LS	$26.83
301 Dark Sky – 9,500 Lumen – Smooth Pole	Moved from LS	$27.98
360 Granville Pole and Fixture, 16000L	$63.76	Eliminated

Adjustment Clauses:
Current
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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Proposed
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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Lighting Energy Service - Rate LE

Rate:

	Current	Proposed
Energy Charge per kWh:	$0.07264	$0.07264

Adjustment Clauses:
Current
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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Proposed
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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Traffic Energy Service - Rate TE

Availability of Service:
Current
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, but not limited to, signals, cameras, or other traffic lights, electronic communication devices, and emergency sirens.

Proposed

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, but not limited to, signals, cameras, or other traffic lights, electronic communication devices, emergency sirens, and gunshot triangulation devices.

Rate:

Current

Basic Service Charge per Month:	$4.00 per delivery
Energy Charge per kWh:	$0.08955

Proposed

Basic Service Charge per Day:	$0.13 per delivery point
Energy Charge per kWh:	$0.08955

Adjustment Clauses:

Current

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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Proposed

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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Pole and Structure Attachment Charges, Terms and Conditions – Rate PSA

Attachment Charges:

Current

$ 7.25 per year for each wireline pole attachment.
$ 0.81 per year for each linear foot of duct.
$36.25 per year for each Wireless Facility located on the top of a Company pole.

Proposed

$ 7.25 per year for each wireline pole attachment.
$ 0.81 per year for each linear foot of duct.
$36.25 per year for each Wireless Facility located on the top of a Company pole.

Revisions to Terms and Conditions:

1) Availability

Expands the types of entities eligible to affix attachments to Company structures to include state, local, and federal governmental units and educational institutions, such as public and private colleges. Provides that current license agreements with governmental units or educational institutions to permit attachments will continue in effect until their expiration date, at which time the attachments will be subject to the PSA Rate Schedule.

2) Penalties

Establishes a penalty of $25 per unauthorized attachment in addition to the assessment of two years of attachment fees. Currently an attachment customer is assessed two years of attachment fees ($14.50) for each unauthorized attachment.

Establishes a penalty for failing to correct an attachment installation that fails to conform to the standards of the National Electrical Safety Code ("NESC"). This penalty is equal to 50% of the Company's actual cost to correct the non-compliant installation and may be imposed only if an attachment customer fails to properly install an attachment and, after receiving notice of the non-compliant installation, fails to correct that installation within the prescribed time.

3) Self-performing Make Ready Work

Requires an attachment customer to notify the Company one week before the start of self-performing make-ready supply space work and to reimburse the Company for the cost of a Company inspector to accompany attachment customer's overhead electric crews. Notice of such work is not currently required.

4) Definition of "Attachment"

Revises definition of attachment to clarify that multiple attachments located within one foot of usable space will not be considered a single attachment and will be in violation of NESC and Company standards.

5) Unauthorized attachments

Establishes that an attachment is an "unauthorized attachment" if (1) a new attachment is made prior to completion of all necessary communications space make-ready, including the transfer of existing attachments to a new pole, or (2) an overlash is made without required advanced notice.

6) Unidentified attachments

Requires reimbursement of the Company's costs to identify the owner of an untagged attachment when the Company must relocate or remove an untagged attachment or otherwise contact the attachment's owner and the owner cannot be readily identified. Provides that the time period in which the owner of an untagged attachment must take corrective action regarding its attachment begins upon the date on which the Company determines that corrective action on the untagged attachment is required.

7) Attachment Audit/Inventory

Requires an attachment customer to bear the cost of periodic attachment audits and inventories.

8) Insurance

Revises required insurance coverage levels and the eligibility requirements for self-insurance.

9) Surety bond

Modifies surety bond requirements to provide a fixed surety requirement based solely upon the number of attachments. Current requirements vary with the stage of construction of the attachment and the length of time that the attachment has been attached.

Electric Vehicle Supply Equipment - EVSE

Rate:

	Current	Proposed
Monthly Charging Unit Fee:		
Single Charger	$182.31	$134.34
Dual Charger	$306.10	$196.64

Adjustment Clauses:

Current

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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Proposed

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
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Electric Vehicle Charging – EVC

Availability:

Current

Available to operators of licensed electric vehicles (EV). EV Customer is defined as the party who owns/operates a licensed electric vehicle, connects that vehicle for the purpose of receiving vehicle charging service to a Company-owned charging station providing service under this schedule, and willingly accepts the Company's fee structure for the vehicle charging service. EVC is offered under the conditions set out hereinafter for the purpose of charging EVs via street parking, parking lots, and other outdoor areas. EV Customers' charging systems must meet applicable charging standards.

Company assumes no liability or responsibility for any potential automotive-related incidents that occur at specific charging locations. EV Customer accepts all restrictions related to the temporary parking space.

Proposed

Available to operators of licensed electric vehicles (EV). EV Customer is defined as the party who owns/operates a licensed electric vehicle, connects that vehicle for the purpose of receiving vehicle charging service to a Company-owned charging station providing service under this schedule, and willingly accepts Company's fee structure for the vehicle charging service. EVC is offered under the conditions set out hereinafter for the purpose of charging EVs via street parking, parking lots, and other outdoor areas. EV Customers' charging systems must meet applicable charging standards. Service under this rate schedule is limited to a maximum of ten stations. Company will accept Customers on a first-come-first-served basis.

Company assumes no liability or responsibility for any potential automotive-related incidents that occur at specific charging locations. EV Customer accepts all restrictions related to the temporary parking space.

Rate:

	Current	Proposed
Fee Per Hour	$2.84	
Fee for First Two (2) Hours (per hour):		$0.75
Fee for Every Hour After First Two (2) Hours (per hour):		$1.00

Adjustment Clauses:

Current

The bill amount computed at the charges specified above includes the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87

The bill amount specified above will be increased or decreased in accordance with the following:

Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Proposed

The bill amount computed at the charges specified above includes the following:

Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87

The bill amount specified above will be increased or decreased in accordance with the following:

Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Special Charges

Returned Payment Charge

Current Rate $10.00
Proposed Rate $ 3.00

Meter Test Charge

Current Rate $75.00
Proposed Rate $75.00

Disconnecting and Reconnecting Service Charge

Current Rate $28.00
Proposed Rate $28.00

Meter Pulse Charge

Current Rate
$15.00 per month per installed set of pulse-generating equipment
Proposed Rate
$25.00 per month per installed set of pulse-generating equipment

Unauthorized Reconnect Charge:

Current

When the Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service:

(1) A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;
(2) A charge of $90.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter;
(3) A charge of $110.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter;
(4) A charge of $174.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter System (AMS) meter; or
(5) A charge of $177.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

Proposed

When the Company determines that Customer has tampered with a meter, reconnected service without authorization from Company that previously had been disconnected by Company, or connected service without authorization from Company, then the following charges shall be assessed for each instance of such tampering or unauthorized reconnection or connection of service:
(1) A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;
(2) A charge of $90.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter;
(3) A charge of $110.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter;
(4) A charge of $174.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Advanced Metering System (AMS) meter; or
(5) A charge of $177.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

Curtailable Service Rider-1 – CSR-1

Rate:

Primary	**Current**	**Proposed**
Monthly Demand Credit Per kVA:	$3.31	$3.31
Non-Compliance Charge Per kVA:	$16.00	$16.00
Transmission	**Current**	**Proposed**
Monthly Demand Credit Per kVA:	$3.20	$3.20
Non-Compliance Charge Per kVA:	$16.00	$16.00

Curtailable Service Rider-2 – CSR-2

Rate:

Primary	**Current**	**Proposed**
Monthly Demand Credit Per kVA:	$6.00	$6.00
Non-Compliance Charge Per kVA:	$16.00	$16.00
Transmission	**Current**	**Proposed**
Monthly Demand Credit Per kVA:	$5.90	$5.90
Non-Compliance Charge Per kVA:	$16.00	$16.00

Standard Rider for Excess Facilities – Rider EF

Customer shall pay for excess facilities by:	**Current**	**Proposed**
(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	1.24%	1.20%

	Current	Proposed
(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%	0.47%

Standard Rider for Redundant Capacity Charge – Rider RC

Availability:

Current

Available to customers requesting the reservation of capacity on Company's facilities which are shared by other customers when Company has and is willing to reserve such capacity. Such facilities represent a redundant delivery to provide electric service to the Customer's facility in the event that an emergency or unusual occurrence renders the Customer's principal delivery unavailable for providing service. Where Customer desires to split a load between multiple meters on multiple feeds and contract for Redundant Capacity on those feeds, service is contingent on the practicality of metering to measure any transferred load to the redundant feed.

Proposed

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

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.

Rate:

Capacity Reservation Charge per Month:	Current (Per kW/kVA)	Proposed (Per kW/kVA)
Secondary Distribution	$1.04	$1.16
Primary Distribution	$0.86	$0.99

Temporary-to-Permanent and Seasonal Service – Rider TS

Availability:

Current

This rider is available at the option of Company where:

1. Customer's business does not require permanent installation of Company's facilities excluding service provided for construction of permanent delivery points for residences and commercial buildings, and is of such nature to require only seasonal service or temporary service; or
2. the service is over 50 kW, provided for construction purposes, 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

3. Customer has need for temporary intermittent use of Company facilities and Company has facilities it is willing to provide Customer for installation and operational testing of Customer's equipment.

This service is available for not less than one (1) month (approximately thirty (30) days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes. Where this service is provided under 2 or 3 above, the Company will determine the term of service, which shall not exceed one (1) year.

Proposed

This rider is available at the option of Company where:

1. Customer's business requires service provided for construction of permanent delivery points for residences and commercial buildings; or

2. Customer's business does not require permanent installation of Company's facilities and is of such nature to require only seasonal service or temporary service; or

3. Customer's service is over 50 kW, provided for construction purposes, 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

4. Customer has need for temporary intermittent use of Company facilities and Company has facilities it is willing to provide Customer for installation and operational testing of Customer's equipment.

This service is available for not less than one (1) month (approximately thirty (30) days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes. Where this service is provided under 3 or 4 above, Company will determine the term of service, which shall not exceed three (3) years.

Conditions:

Current

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

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

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

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

Proposed

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. For Temporary-to-Permanent service which requires service for construction of permanent delivery points for residences and commercial buildings, the Company will provide a temporary electric service upon request by the customer for a non-refundable charge. This charge, which will be subject to an annual review and revision, shall depend on the facilities which must be installed (and removed) by the Company in order to connect service.

The standard charge shall be 15% of the estimated installation and removal cost where the facilities to provide service are already in place. It also applies where all of the installed facilities will be utilized, without modification, as part of a future permanent service.

2. For Seasonal Service where facilities are installed for temporary service that will not be utilized as part of a future permanent service, the 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.

Temporary services for underground or overhead installations are to be constructed as specified by Company standards. Customer will furnish and install material and equipment, including mast for service entrance, conductors, meter base, main disconnect, breaker assembly and grounding. Once the temporary service is no longer needed, the Customer must contact the Company for removal.

For such cases where a temporary service is written upon a refundable contract, the customer will be refunded back the deposit paid for the temporary service after three years of continuous service.

<u>Green Tariff – Rider GT</u>

New Tariff – Replaces Small Green Energy Rider (SGE) and Large Green Energy Rider (LGE)

The Company is adding a new Green Tariff to ensure that businesses inside and outside Kentucky know that the Company has multiple renewable offerings. The new Green Tariff provides three options for customers seeking to support the development of renewable energy resources.

The first option is the continuation of the Company's existing Small Green Energy and Large Green Energy programs (Riders SGE and LGE), which the Company proposes to remove from its tariff as separate riders and incorporate into a single option under the new Green Tariff. None of the pricing or substantive terms of the existing Riders SGE and LGE will change in Green Tariff option 1.

The second option in the new Green Tariff is the Business Solar option. This option will continue and formalize as a tariff offering the Company's existing Business Solar program. The program is for non-residential customers seeking to have solar facilities constructed and owned by the Company. The Company arranges for the design, installation, and ongoing operation and maintenance of the facilities. Business Solar customers receive two significant benefits: (1) the benefit of additionality, i.e., causing entirely new solar facilities to be constructed, and (2) the benefit of receiving the value of the facilities' output.

The Company will require a contract with a customer under the Business Solar option to obtain reasonable assurances of cost recovery, and will file all such contracts with the Commission.

The third Green Tariff option will allow customers to engage with the Company to consider entering into renewable energy purchase agreements to supply some or all of a customer's energy needs. To be eligible for option 3, a customer must have load of 10 MVA or more and be willing to enter into an obligation for 10 MW or more of new (not already existing) renewable capacity. The energy from the new renewable facility must be delivered to the Company's transmission system. The minimum term of the contract into which the customer must enter with the Company is five years and is equivalent to the term of the agreement with the renewable energy provider. The Company will file all such contracts with the Commission. The Company proposes to limit this offering to 50 MW.

<u>Economic Development Rider – Rider EDR</u>

Rate:

<u>Current</u>

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.

Proposed

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:

For the twelve (12) consecutive monthly billings and the subsequent four consecutive twelve (12) monthly billing periods thereafter, the Total Demand Charge shall be reduced by 50%, 40%, 30%, 20%, 10% in the order of Customers choosing at time of contract filing. All subsequent billing shall be at the full charges stated in the applicable rate schedule after this five (5) year period.

"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:

Current

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 minimum monthly billing loads of 500 kVA or greater where the customer takes service from existing Company facilities.

Economic Development

c) Service under EDR for Economic Development is available to:
1) new customers contracting for a minimum monthly billing load of 1,000 kVA; and
2) existing customers contracting for a minimum monthly billing load of 1,000 kVA above their Existing Base Load, to be determined as follows:
i. Company and the existing customer will determine Customer's Existing Base Load by calculating a 12-month rolling average of measured demand.
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 (KBI), or the Kentucky Industrial Revitalization Act (KIRA), or the Kentucky Jobs Retention Act (KJRA), or other comparable programs approved by the Commonwealth of Kentucky.

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 Kentucky Public Service Commission.

j) In any billing month where Customer's metered load is less than the load required to be eligible for either Brownfield Development or Economic Development, no credit under EDR will be calculated or applied to Customer's billing.

Proposed

Brownfield Development

1. 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).
2. EDR for Brownfield Development is available only to minimum monthly billing loads of 500 kVA or greater where the Customer takes service from existing Company facilities with no material changes.

Economic Development

3. Service under EDR for Economic Development is available to:

a. new Customers contracting for a minimum monthly billing load of 1,000 kVA, and at least a 50% load factor; and

b. Existing Customers contracting for a minimum monthly billing load of 1,000 kVA above their Existing Base Load, and at least a 50% load factor to be determined as follows:

i. Company and the existing Customer will determine Customer's Existing Base Load by calculating a twelve (12) month rolling average of measured demand.

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 Company and the Customer concerning the affected portion of the Customer's Existing Base Load.

4. A Customer desiring service under EDR for Economic Development must submit an application for service that includes:

a. a description of the new load to be served;

b. the number of new employees, if any, Customer anticipates employing associated with the new load;

c. the capital investment Customer anticipates making associated with the EDR load;

d. a certification that Customer has been qualified by the Commonwealth of Kentucky for benefits under the Kentucky Business Investment Program (KBI), or the Kentucky Industrial Revitalization Act (KIRA), or the Kentucky Jobs Retention Act (KJRA), or other comparable programs approved by the Commonwealth of Kentucky.

5. 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.

Economic Re-Development

6. Service under EDR for Economic Re-Development is available to:

a. Customers locating at vacant commercial or industrial properties in the Company's service territory which have been unoccupied for at least twelve (12) consecutive months. Verification of vacancy will constitute evidence of minimal to no electrical use during the unoccupied timeframe as determined by the company. Development of green space or undeveloped properties or sites are excluded from the Re-Development rider.

b. EDR for Economic Re-Development is available only to minimum monthly billing loads of 500 kVA or greater where Customer takes service from the existing electrical infrastructure with no material changes and at least a 50% load factor.

c. A customer desiring service under must submit an application for service that includes:

i. a description of the new load to be served;

ii. the number of new employees, if any, Customer anticipates employing associated with the new load; and

iii. the capital investment Customer anticipates making associated with the EDR load.

d. Customers relocating their operations from another premise within the company's service territory and maintaining the same demand load as indicated on the customer's Load Data Sheet are ineligible to participate in this tariff.

e. Customers relocating their operations from another premise within the company's service territory and increasing the demand load as indicated on the customer's Load Data Sheet are eligible to participate in this tariff for the increased demand of 500 kVA minimum and at least a 50% load factor.

f. 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 forth under Company's Line Extension Plan, that amount shall be determined over a fifteen (15) year period and payable at the end of the fifteen (15) year period

General

7. 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.

8. Customer may request an EDR effective initial billing date that is no later than twelve (12) months after the date on which the Kentucky Public Service Commission approves the customer agreement.

9. 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.

10. 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 Kentucky Public Service Commission.

11. No credit under EDR will be calculated or applied to Customer's billing in any billing month in which Customer's metered load is less than the load required to be eligible for either Brownfield Development, Economic Development, or Economic Re-Development no credit under EDR will be calculated or applied to Customer's billing.

12. EDR is not available to a new customer that results solely from a change in ownership of a previous customer's account. However, if a change in ownership occurs after the previous customer had entered into an EDR special contract, the successor customer may be allowed to fulfil the balance of the EDR special contract.

Solar Share Program Rider – Rider SSP

Availability:

Current

This optional, voluntary service is available to Company's customers taking service under any Standard Rate Schedule except those served under Retail Transmission Service, Fluctuating Load Service, Lighting Service, Restricted Lighting Service, Lighting Energy Service, Traffic Energy Service, Pole and Structure Attachment Charges, Electric Vehicle Supply Equipment, and Electric Vehicle Charging Service rate schedules. The terms and conditions set out herein are available for and applicable to participation in Company's Solar Share Program.

Proposed

This optional, voluntary service is available to Customers taking service under Rates RS, RTOD-Energy, RTOD-Demand, VFD, GS, AES, PS, TODS, and TODP. The terms and conditions set out herein are available for and applicable to participation in Company's Solar Share Program.

Rate:

		Current Per kW Subscribed	Proposed Per kW Subscribed
Solar Capacity Charge :			
One-Time Solar Capacity Charge			$790
Monthly Solar Capacity Charge		$6.27	$5.68
Current			
Monthly Credits and Adjustments	Rate Schedule	Credit per kWh	
Solar Energy Credit (per kWh of pro rata energy produced by the Solar Share Facilities; number of kWh eligible for credit limited to customer's net kWh consumption on each bill)	RS	$0.03237	
	RTOD-Energy	$0.03237	
	RTOD-Demand	$0.03237	
	VFD	$0.03237	
	GS	$0.03241	
	AES	$0.03243	
	PS Secondary	$0.03270	
	PS Primary	$0.03171	
	TODS	$0.03229	
	TODP	$0.03136	
Solar FAC Adjustment		Subscriber's billing under Adjustment Clause FAC will be adjusted corresponding to number of kWh to which Solar Energy Credit applies	

<u>Proposed</u>

Solar Energy Credit

Each billing period during which the Subscriber has paid in full for subscribed capacity under either option above, Company will compare a subscribing customer's pro rata AC energy produced by the Solar Share Facilities (truncated to a whole kWh value) to the subscribing customer's energy consumption (in kWh) every 15 minutes. If consumption exceeded production, Company will bill Customer for the net energy consumed in accordance with Customer's standard rate schedule. If production equaled or exceeded consumption in any relevant period, Company will bill Customer for zero energy consumption for that period and provide a bill credit for each kWh of net production, if any, at the then-applicable non-time-differentiated rate for Company's Standard Rate Rider SQF, (Small Capacity Cogeneration and Small Power Production Qualifying Facilities) Original Sheet No. 55.

Program Description:

<u>Current</u>

The Solar Share Program is an optional, voluntary program that allows customers to subscribe capacity in the Solar Share Facilities. Each Solar Share Facility will have an approximate direct-current (DC) capacity of 500 kW and will be available for subscription in nominal 250 W (quarter-kW) DC increments. Each subscribing customer ("Subscriber") may subscribe capacity up to an aggregate amount of 500 kW DC, though no Subscriber may subscribe more than 250 kW DC in any single Solar Share Facility.

Subscriber's desired capacity will be considered subscribed upon Subscriber's commitment to pay charges under this Rider for at least 12 billing periods (or enters in a contract as required herein for subscriptions of 50 kW DC or more). Subscriber will pay the monthly Solar Capacity Charge for each quarter-kW subscribed beginning with the first billing period in which the subscribed capacity has been in service for the entire billing period. For each such billing period, Subscriber will also receive (i) a bill credit in the amount of the monthly Solar Energy Credit (see Rate above) times the pro rata amount of energy production attributable to Subscriber's subscribed capacity (limited by Subscriber's net kWh consumption for the period being billed) and (ii) a bill adjustment to the Subscriber's Fuel Adjustment Clause (FAC) credits or charges corresponding to the number of kWh for which the Subscriber receives a Solar Energy Credit.

Customers subscribing less than 50 kW DC will not be required to enter into a contract concerning their subscriptions; however, a customer may not reduce or cancel a subscription earlier than 12 months from the date of the customer's most recent change to the customer's subscription level following the first billing period for which Subscriber pays Solar Capacity Charges. Therefore, a customer subscribing less than 50 kW has a 12-month payment commitment, and may have a longer commitment if the customer subsequently increases subscribed capacity (which a customer may do at any time) or if the customer chooses to decrease but not cancel the subscription after the initial 12 months. As addressed in Term of Contract below, customers subscribing 50 kW DC or more must enter into a 5-year contract with Company.

<u>Proposed</u>

The Solar Share Program is an optional, voluntary program that allows customers to subscribe to capacity in the Solar Share Facilities. Each Solar Share Facility will have an approximate direct-current (DC) capacity of 500 kW and will be available for subscription in nominal 250 W (quarter-kW) DC increments. Each subscribing customer ("Subscriber") may subscribe capacity up to an aggregate amount of 500 kW DC, though no Subscriber may subscribe more than 250 kW DC in any single Solar Share Facility.

There are two mutually exclusive options for subscribing to each increment of capacity.

Option 1: Capacity Subscribed by Paying Only the One-Time Solar Capacity Charge

For capacity subscribed by paying the One-Time Solar Capacity Charge, the One-Time Solar Capacity Charge will be included on the Subscriber's bill for the first billing period in which the subscribed capacity achieves commercial operation.

A customer choosing to pay the One-Time Solar Capacity Charge may transfer subscribed capacity between the customer's own accounts or may assign subscribed capacity to another customer. Once assigned, the assigning customer forfeits all rights to the assigned capacity.

A customer who ceases taking service from Company will have 60 calendar days to assign subscribed capacity to another customer within Company's service area. Any capacity such a customer does not assign within 60 days of ceasing to take service will be forfeited and made available to other customers under Option 2: Capacity Subscribed by Paying Only the Monthly Solar Capacity Charge.

Option 2: Capacity Subscribed by Paying Only the Monthly Solar Capacity Charge

For capacity subscribed by paying the Monthly Solar Capacity Charge, the Solar Capacity Charge will be included on the Subscriber's bill beginning with the bill for the first billing period in which the subscribed capacity achieves commercial operation.

Monthly subscriptions of less than 50 kW DC will not require a contract; however, a customer may not reduce or cancel a monthly subscription earlier than 12 months from the date of the customer's most recent change to the customer's monthly subscription level. Therefore, a customer subscribing monthly less than 50 kW has a 12-month commitment from the date of the customer's initial monthly subscription or initial solar facility commercial operation, whichever is later, and may have a longer commitment if the customer subsequently increases monthly subscribed capacity (which a customer may do at any time) or if the customer chooses to decrease but not cancel the monthly subscription after the initial 12 months. Monthly subscriptions of 50 kW DC or more require a 5-year contract with Company.

Terms and Conditions:
<u>Current</u>

1) Subscriptions will be available on a first-come first-served basis, except that 25% of the capacity of Solar Share Facility No. 1 will be available only to residential customers for the first 45 days of the initial subscription period for new facility. Otherwise, all capacity in the Solar Share Facilities will be available for subscription by all customers on a first-come, first-served basis.
2) Individual subscriptions will be available in nominal 250 W DC (quarter-kW) increments.
3) Customer may subscribe as much solar capacity as desired up to an aggregate amount of 500 kW DC. No customer may subscribe more than 250 kW DC in any single Solar Share Facility.
4) Subject to the restrictions above, Company will fill subscriptions as capacity in the Solar Share Facilities becomes available, and will fill subscriptions in the chronological order in which the subscriptions were made. A Subscriber whose subscription the Company can fulfill only partially may either accept the available capacity and await additional capacity, or decline the partial fulfillment, allowing the next awaiting Subscriber(s) to accept the available capacity. Accepting or declining available capacity will not affect a Subscriber's place in the queue of Subscribers awaiting capacity.
5) Customers may not owe any arrearage prior to participating in the Solar Share Program.
6) Subscribers' pro-rata share of the electricity produced by the Solar Share Facilities will be determined on a billing cycle basis. The corresponding Solar Energy Credit (per kWh) and Solar FAC Adjustment will appear on the Subscriber's bill.

7) Subscriber may continue to participate in the Program if Subscriber changes premises within the combined Kentucky certified electric service territories of Louisville Gas and Electric Company and Kentucky Utilities Company.
8) Subscribers whose customer accounts are closed for any reason will not be able to remain in the Program. Upon account closing, Subscriber will be obligated to pay Solar Capacity Charges for any remaining commitment period(s) associated with Subscriber's capacity, e.g., a Subscriber closing an account after having paid only six billing periods' Solar Capacity Charges for less than 50 kW DC subscribed capacity would be obligated to pay the remaining six billing periods' Solar Capacity Charges at the time of account closing.
9) Unless constrained by contract (see Term of Contract below), Subscriber may decrease or terminate a subscription any time after 12 months following the date of the most recent change to Subscriber's subscription that occurs after the first billing period for which Subscriber pays Solar Capacity Charges.
10) Unless constrained by contract (see Term of Contract below), Subscriber may also increase subscribed capacity at any time.
11) Each subscription under the Solar Share Program applies to a particular meter. Subscribers with multiple meters may obtain multiple subscriptions, one per meter. But Company will not aggregate usage across multiple meters for applying credits, charges, or adjustments under Rider SSP; credits, charges, and adjustments under Rider SSP apply only to the meter associated with the subscription. The only exception to this restriction is if Subscriber has more than one meter for a single service, which multiple meters Company installed for its own operating convenience and bills on an aggregated basis in accordance with Company's Terms and Conditions.
12) Subscriptions are not transferrable or assignable between customers or between a single customer's meters.
13) Subscriber's Solar Energy Credit and corresponding Solar FAC Adjustment will apply each billing cycle to the Subscriber's pro rata amount of AC energy produced by the Solar Share Facilities (truncated to a whole kWh value) or Subscriber's net energy consumption (kWh) for the billing period, whichever is less.
14) For all customers taking service under both of Riders NMS and SSP, Company will apply all provisions of Rider NMS to their bills before applying charges and credits under Rider SSP, including applying the Solar Energy Credit and Solar FAC Adjustment to such customers' net energy consumption. Therefore, customers should note that in months in which a customer taking service under Riders SSP and NMS has net zero energy consumption or net energy production under the terms of Rider NMS—including carryover net-energy credits from previous months, if any—the customer will receive zero Solar Energy Credit and Solar FAC Adjustment under Rider SSP. These provisions apply regardless of whether a customer first took service under Rider NMS before taking service under Rider SSP or vice versa, or if a customer began taking service under both riders simultaneously.
15) All Renewable Energy Credits ("RECs") related to energy produced by subscribed portions of the Solar Share Facilities will be retired.
16) Use of any images of the Solar Share Facilities or use any other of Company's intellectual property requires Company licensing prior to use.
17) Service will be furnished under Company's Terms and Conditions except as provided herein.

Proposed

1. Individual subscriptions are available in nominal 250 W DC (quarter-kW) increments.
2. Customer may subscribe as much solar capacity as desired up to an aggregate amount of 500 kW DC (nominal). No customer may subscribe more than 250 kW DC (nominal) in any single Solar Share Facility.
3. All One-Time Solar Capacity Charges are non-refundable.

4. Subject to the restrictions above, Company will fill subscriptions as capacity in the Solar Share Facilities becomes available, and will fill subscriptions in the chronological order in which the subscriptions were made. A Subscriber whose subscription the Company can fulfill only partially may either accept the available capacity and await additional capacity, or decline the partial fulfillment, allowing the next awaiting Subscriber(s) to accept the available capacity. Accepting or declining available capacity will not affect a Subscriber's place in the queue of Subscribers awaiting capacity.
5. Customers may not owe any arrearage prior to participating in the Solar Share Program.
6. Subscribers' pro-rata share of the AC electricity produced by the Solar Share Facilities will be determined on a billing-cycle basis. The corresponding Solar Energy Credit will be calculated and appear on the Subscriber's bill.
7. Unless constrained by contract (see Term of Contract below), Subscriber may decrease or terminate a monthly subscription any time after 12 months following the date of the most recent change to Subscriber's monthly subscription capacity at any time.
8. Unless constrained by contract (see Term of Contract below) or condition #2 above, Subscriber may also increase monthly subscribed capacity at any time.
9. Subscriptions made by paying the One-Time Solar Capacity Charge may be transferred between a Subscriber's accounts no more than once per billing period (Solar Energy Credit values do not transfer between accounts or customers). A subscription transfer between a Subscriber's accounts takes effect in the billing period following the billing period in which the Subscriber requests the transfer. A Subscriber may transfer a subscription at any time prior to or including 60 calendar days after the Subscriber terminated service on the account to which the subscription attached. If the Subscriber whose account has been terminated does not transfer the subscription within 60 calendar days, the Subscriber forfeits the subscription.
10. Capacity subscribed by paying the Monthly Solar Capacity Charge is not transferrable or assignable between customers.
11. Capacity subscribed by paying the One-Time Solar Capacity Charge may be assigned between customers, but only within the same Company service territory, at any time prior to or including 60 calendar days after the assigning Subscriber terminated service on the account to which the subscription attached. Once assigned, the assigning customer loses all rights regarding future credits and the ability to subsequently assign the capacity; those rights become the rights of the assignee upon assignment. Assigned capacity cannot be reassigned by the assignee to any other Customer, including the Customer who originally subscribed the assigned capacity. For all purposes other than the Solar Energy Credit, all capacity assignments become effective immediately upon assignment. For the purpose of the Solar Energy Credit, the assignor will receive Solar Energy Credits for the entire billing period in which the assignment occurs; the assignee will receive Solar Energy Credits beginning in the first billing period following the assignment.
12. Unused Solar Energy Credit value is not transferrable between customers or customer accounts. Therefore, a Subscriber's closing a customer account terminates any unused Solar Energy Credit value associated with that account.
13. Participants in SSP are required to have an advanced meter capable of collecting and communicating at least 15 minute interval data.
14. All Renewable Energy Credits ("RECs") related to energy produced by subscribed portions of the Solar Share Facilities will be retired.
15. Use of any images of the Solar Share Facilities or use any other of Company's intellectual property requires Company licensing prior to use.
16. Service will be furnished under Company's Terms and Conditions except as provided herein.

Term of Contract:

Current

Subscriptions of 50 kW DC or more will require a five (5) year non-transferrable, non-assignable contract between Subscriber and Company.

Proposed
Subscriptions of 50 kW DC or more will require a five (5) year non-transferrable, non-assignable contract between Subscriber and Company.

Electric Vehicle Supply Equipment – Rider EVSE-R

Monthly Charging Unit Fee	Current	Proposed
Single Charger	$131.41	$123.99
Dual Charger	$204.31	$175.95

School Power Service (SPS) and School Time-of-Day Service (STOD) rates are being eliminated

Outdoor Sports Lighting Service – Pilot OSL

Rate:

Secondary	Current	Proposed
Basic Service Charge per month	$90.00	
Basic Service Charge per day		$2.96
Plus and Energy Charge per kWh of:	$0.03288	$0.03270
Plus a Maximum Load Charge per kW of:		
Peak Demand Period	$16.75	$19.42
Base Demand Period	$3.03	$3.03
Primary	**Current**	**Proposed**
Basic Service Charge per month	$240.00	
Basic Service Charge per day		$7.89
Plus and Energy Charge per kWh of:	$0.03189	$0.03189
Plus a Maximum Load Charge per kW of:		
Peak Demand Period	$16.88	$19.57
Base Demand Period	$3.03	$2.87

Adjustment Clauses:
Current
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
Off-System Sales Adjustment Clause	Sheet No. 88
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Tax Cuts and Jobs Act Surcredit	Sheet No. 89
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

Proposed
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
Fuel Adjustment Clause	Sheet No. 85
Off-System Sales Adjustment Clause	Sheet No. 88
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee	Sheet No. 90
School Tax	Sheet No. 91

Rating Periods:

Current

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:

	Base	Peak
Weekdays	All Hours	1 PM - 7 PM
Weekends	All Hours	

All other months of October continuously through April

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

Proposed

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	Peak
Weekdays	All Hours	1 PM - 7 PM
Weekends	All Hours	

All other months of October continuously through April

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

If a legal holiday falls on a weekday, it will be considered a weekday.

Demand-Side Management Cost Recovery Mechanism

Availability

Current

This schedule is mandatory to Residential Service Rate RS, Residential Time-of-Day Energy Rate RTOD-Energy, Residential Time-of-Day Demand Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, Retail Transmission Service Rate RTS, School Power Service Rate SPS, School Time-of-Day Service Rate STOD, and Outdoor Sports Lighting Service Rate OSL. 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."

Proposed

This schedule is mandatory to Residential Service Rate RS, Residential Time-of-Day Energy Rate RTOD-Energy, Residential Time-of-Day Demand Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, Retail Transmission Service Rate RTS, and Outdoor Sports Lighting Service Rate OSL. 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."

Environmental Cost Recovery Surcharge

Availability of Service:

Current

This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC (including the Off-System Sales Tracker) 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; RTOD-Energy; RTOD-Demand; VFD; AES; LS; RLS; LE; and TE.
Group 2: Rate Schedules GS; PS; TODS; TODP; RTS; FLS; EVSE; EVC; SPS; STOD; and OSL.

Proposed

This schedule is mandatory to all rate schedules listed in Section 1 of the General Index except Rate PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and FAC (including OSS) and DSM Adjustment Clauses. Rate schedules subject to this adjustment clause are divided into Group 1 or Group 2 as follows:

Group 1: Rates RS; RTOD-Energy; RTOD-Demand; VFD; AES; LS; RLS; LE; and TE.
Group 2: Rates GS; PS; TODS; TODP; RTS; FLS; EVSE; EVC; and OSL.

Tax Cuts and Jobs Act Surcredit (TCJA) Adjustment Clause withdrawn from tariff and cancelled

The approval of a change in KU's base rates will cause the Tax Cuts and Jobs Act ("TCJA") Surcredit Tariff to be withdrawn from service and associated billing credits cancelled effective May 1, 2019. The TCJA Surcredit is a rate mechanism that provides a monthly credit that reduces customers' bills. In its base rate application, KU is proposing to include all changes associated with the TCJA in the calculation of its proposed base rates. When the new base rates become effective, customers will no longer receive the credit provided by the TCJA Surcredit mechanism. The monthly residential electric bill increase due to the proposed electric base rates will be 8.1 percent, or approximately $9.63, for a customer using 1,139 kWh of electricity (the average monthly consumption of a KU residential customer). KU is proposing to withdraw Adjustment Clause TCJA from service and cancelling the associated billing credits effective when new base rates change. When the TCJA Surcredit is cancelled when new base rates take effect, the total monthly residential electric bill increase will be 11.7%, or approximately $13.47, for a customer using 1,139 kWh of electricity.

Franchise Fee – FF

Proposed

DEFINITIONS and RATE sections will only be applicable to franchise fee agreements before September 21, 2011

Term of Contract:

Current

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.

Proposed

As agreed to in the franchise agreement. Company will not calculate or collect any such fees, taxes, or charges pursuant to expired, lapsed, or otherwise invalid, ineffective or inapplicable ordinances, franchise agreements, or other governmental enactment.

Terms and Conditions:

Current

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.

Proposed

This section has been removed.

Terms and Conditions – Character of Service

Current

TRANSMISSION VOLTAGES

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

Proposed

TRANSMISSION VOLTAGES

According to location, 69,000 volts, 138,000 volts, 161,000 volts, or 345,000 volts.

Terms and Conditions – Billing

Meter Readings and Bills:

Current

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.

Proposed

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 (30) days, unless an applicable rate schedule has a daily Basic Service Charge, in which case a full daily Basic Service Charge will be charged to a customer for each day or partial day during which the customer's account was open and served under that rate schedule.

Minimum Charge:

Current

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.

Proposed

Without limiting the foregoing, the Basic Service Charge and Demand Charge shall apply and be due for all times during which a customer's account is open, 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

Current Rate

For Customers Served Under Residential Service Rates RS, RTOD-Energy, and RTOD-Demand:	$160.00
For Customers Served Under General Service Rate GS	$240.00

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.

Proposed Rate

For Customers Served Under Residential Service Rates RS, RTOD-Energy, and RTOD-Demand:	$160.00
For Customers Served Under General Service Rate GS	$240.00

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.

Terms and Conditions – Line Extension Plan

Current

D. NORMAL LINE EXTENSIONS

1) In accordance with 807 KAR 5:041, Section 11(1), Company will provide, at no cost, a line extension of up to 1,000 feet to Customer requesting permanent service where the installed transformer capacity does not exceed 25 kVA.

2) Where Customer requires poly-phase service or transformer capacity in excess of 25 kVA and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ 1 above.

Proposed

4. NORMAL LINE EXTENSIONS

a. In accordance with 807 KAR 5:041, Section 11(1), Company will provide, at no cost, a line extension of up to 1,000 feet to Customer requesting permanent service where the installed transformer capacity does not exceed 25 kVA.

b. Where Customer requires poly-phase distribution service or transformer capacity in excess of 25 kVA and Company provides such facilities, Company shall provide requested line extension to the extent the cost of an overhead extension, whether request is for overhead or underground, does not exceed five (5) times the Customers estimated annual net revenue, where “net revenue is defined as the Customer’s total revenue (less base fuel, Fuel Adjustment Clause, Off-System Sales, Demand Side Management, franchise fees, and school taxes). Company may require Customer to pay, in advance, a non-refundable amount for the additional cost above the five (5) times net revenue calculation to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ a. above. Customer must commit to a minimum contract term of five (5) years.

Current

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) 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.

5) Where Customer requires poly-phase service or transformer capacity above 25 kVA per customer and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in OTHER LINE EXTENSIONS ¶ 1 above.

<u>Proposed</u>

5. OTHER LINE EXTENSIONS

a. 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.

b. After the ten (10) year period following the line extension, 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 the first ten (10) year period directly to the original extension for which the deposit was made.

c. After the ten (10) year period following the line extension, 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 the first ten (10) year period by a lateral or extension to the original extension for which the deposit was made.

d. 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.

e. Where Customer requires poly-phase distribution service or transformer capacity in excess of 25 kVA and Company provides such facilities, Company shall provide requested line extension to the extent the cost of an overhead extension, whether request is for overhead or underground, does not exceed five (5) times the Customers estimated annual net revenue, where "net revenue is defined as the Customer's total revenue (less base fuel, Fuel Adjustment Clause, Demand Side Management, franchise fees, and school taxes). Company may require Customer to pay, in advance, a non-refundable amount for the additional cost above the five (5) times net revenue calculation to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ a. above.

<u>Underground Line Extensions</u>

<u>Removed</u>

6) In consideration of Customer's underground service, Company shall credit any amounts due under the contract for each service at the rate of $50.00 or Company's average estimated installed cost for an overhead service whichever is greater.

<u>Current</u>

Individual Premises

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

<u>Proposed</u>

b. Individual Premises

Where Customer requests and Company agrees to supply underground service (primary) to an individual premise, Company may require Customer to furnish ditching, conduit, backfill, and transformer pad. Company will then use overhead extension policy requirements.

Kentucky Utilities Company also proposes to change the text of the following electric tariffs: Residential Service Rate RS, Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day Demand Service Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, All Electric School Rate AES, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, Retail Transmission Service Rate RTS, Fluctuating Load Service Rate FLS, Lighting Service Rate LS, Restricted Lighting Service Rate RLS, Lighting Energy Service Rate LE, Traffic Energy Service Rate TE, Electric Vehicle Supply Equipment Rate EVSE, Electric Vehicle Charging Rate EVC, Special Charges, Curtailable Service Rider-1 CSR-1, Curtailable Service Rider-2 CSR-2, Temporary-to-Permanent and Seasonal Service Rider TS, Green Tariff Rider GT, Economic Development Rider EDR, Solar Share Program Rider SSP, Electric Vehicle Supply Equipment Rider EVSE-R, Outdoor Sports Lighting Pilot Program OSL, Environmental Cost Recovery Surcharge ECR, Franchise Fee Adjustment Clause FF, Home Energy Assistance Program Adjustment Clause HEA, and the Terms and Conditions.

Complete copies of the proposed tariffs containing text changes and proposed rates,terms and conditions may be obtained by contacting Kentucky Utilities Company at 220 West Main Street, Louisville, Kentucky, the Residential Call Center at 1-800-981-0600, or visiting Kentucky Utilities Company's website at www.lge-ku.com. A copy of this customer notice required by 807 KAR 5:001 Section 17 is posted and may be viewed in each public library located within KU's service territory or at the KU offices where bills are paid.

The foregoing rates reflect a proposed annual increase in revenues of approximately 7.11% to Kentucky Utilities Company.

The estimated amount of the annual change and the average monthly bill to which the proposed electric rates will apply for each electric customer class is as follows:

Electric Rate Class	Average Usage (kWh)	Annual $ Increase	Annual % Increase	Monthly Bill $ Increase	Monthly Bill % Increase
Residential	1,139	50,433,651	8.10	9.63	8.10
Residential Time-of-Day Energy	1,142	6,406	8.11	8.68	8.11
General Service	1,717	15,621,049	6.61	15.41	6.61
All Electric School	19,744	852,252	6.60	127.28	6.61
Power Service	34,810	12,186,004	6.61	217.19	6.61
Time-of-Day Secondary	208,133	8,381,858	6.11	949.03	6.11
Time-of-Day Primary	1,294,965	15,925,393	6.11	5,117.42	6.11
Retail Transmission	4,908,868	5,347,588	6.12	17,825.29	6.12
Fluctuating Load	51,873,999	2,077,780	6.12	173,148.31	6.12
Outdoor Lights	59	2,090,440	6.61	1.00	6.59
Lighting Energy	3,573	0.00	0.00	0.00	0.00
Traffic Energy	171	(396.00)	(0.21)	(0.04)	(0.20)
PSA	N/A	0.00	0.00	0.00	0.00
Rider – CSR	N/A	0.00	0.00	0.00	0.00
Outdoor Sports Lighting – Pilot Program	5,204	3,921	6.62	54.45	6.62

The monthly residential electric bill increase due to the proposed electric base rates will be 8.1 percent, or approximately $9.63, for a customer using 1,139 kWh of electricity (the average monthly consumption of a KU residential customer). KU is proposing to withdraw Adjustment Clause TCJA from service and cancelling the associated billing credits effective when new base rates change. When the TCJA Surcredit is cancelled when new base rates take effect, the total monthly residential electric bill increase will be 11.7%, or approximately $13.47, for a customer using 1,139 kWh of electricity.

Notice is further given that a person may examine this application at the offices of Kentucky Utilities Company, 100 Quality Street, Lexington, Kentucky, or through Kentucky Utilities Company's website at www.lge-ku.com. A person may also examine this application at the Public Service Commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the commission's Web site at http://psc.ky.gov.

Comments regarding the application may be submitted to the Public Service Commission, by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, through its Web site, or by sending an email to the Commission's Public Information Officer at psc.info@ky.gov. All comments should reference Case No. 2018-00294.

The rates contained in this notice are the rates proposed by Kentucky Utilities Company, but the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice. A person may submit a timely written request for intervention to the Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party. If the commission does not receive a written request for intervention within thirty (30) days of initial publication or mailing of the notice, the commission may take final action on the application.

Kentucky Utilities Company
c/o LG&E and KU Energy LLC
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40232
1-800-981-0600

Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602
502-564-3940

Exhibit D

Listing of Library Notice

List of Libraries in KU Territory
Adair County Public Library
Anderson County Public Library
Ballard-Carlislelivingston Public Library
Bath County Memorial Library
Beaumont Branch
Bell County Public Library District
Boyle County Public Library
Bracken County Public Library
Burnside Branch/SOMERSET PUL CO LIBRARY
Carroll County Public Library District
Casey County Public Library
Central City Public Library
Clark County Public Library
Clay County Public Library
Crittenden County Public Library
Cynthiana-Harrison County Public Library
Dawson Springs Branch
Eagle Creek Branch
Estill County Public Library
Gallatin County Public Library
Garrard County Public Library
Green County Public Library
Hardin County Public Library
Hardin County Public Library
Harlan County Public Library
Hart County Public Library
Henry County Public Library
Hickman County Memorial Library
Larue County Public Library
Lebanon Junction Branch Library
Lexington Public Library
Lincoln County Public Library
Logan Helm Woodford County Library
Lyon County Public Library
Madison County Public Library
Marion County Public Library
Mason County Public Library
Mccreary County Public Library District
McLean County Public Library
Mercer County Public Library
Mt. Sterling - Montgomery County Library
Muhlenberg County Public Libraries
New Haven Branch
Nicholas County Public Library
Northside Branch

Ohio County Public Library
Oldham County Public Library
Pulaski County Public Library
Rebecca Caudill Public Library
Robertson County Public Library
Rockcastle County Public Library
Rowan County Public Library
Russell County Public Library District
Russell Springs Branch Library
Science Hill Branch
Scott County Public Library
Shelby County Public Library
Spencer County Public Library
Sturgis Branch
Tates Creek Branch
Taylor County Public Library
Trimble County Public Library
Union County Public Library District
Uniontown Branch
Washington County Public Library
Webster County Public Library
Whitley County Public Library

Exhibit E

Customer Bill Insert
General Statement

NOTICE TO CUSTOMERS OF
KENTUCKY UTILITIES COMPANY

PLEASE TAKE NOTICE that, in a September 28, 2018 Application, Kentucky Utilities Company ("KU") is seeking approval by the Kentucky Public Service Commission of an adjustment of its rates and charges to become effective on and after November 1, 2018.

The proposed rates reflect a proposed annual increase in revenues of approximately 7.11% to KU.

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 are as follows:

Electric Rate Class	Average Usage (kWh)	Annual $ Increase	Annual % Increase	Monthly Bill $ Increase	Monthly Bill % Increase
Residential	1,139	50,433,651	8.10	9.63	8.10
Residential Time-of-Day Energy	1,142	6,406	8.11	8.68	8.11
General Service	1,717	15,621,049	6.61	15.41	6.61
All Electric School	19,744	852,252	6.60	127.28	6.61
Power Service	34,810	12,186,004	6.61	217.19	6.61
Time-of-Day Secondary	208,133	8,381,858	6.11	949.03	6.11
Time-of-Day Primary	1,294,965	15,925,393	6.11	5,117.42	6.11
Retail Transmission	4,908,868	5,347,588	6.12	17,825.29	6.12
Fluctuating Load Service	51,873,999	2,077,780	6.12	173,148.31	6.12
Outdoor Lights	59	2,090,440	6.61	1.00	6.59
Lighting Energy	3,573	0.00	0.00	0.00	0.00
Traffic Energy	171	(396.00)	(0.21)	(0.04)	(0.20)
PSA	N/A	0.00	0.00	0.00	0.00
Rider – CSR	N/A	0.00	0.00	0.00	0.00
Outdoor Sports Lighting – Pilot Program	5,204	3,921	6.62	54.45	6.62

The monthly residential electric bill increase due to the proposed electric base rates will be 8.1 percent, or approximately $9.63, for a customer using 1,139 kWh of electricity (the average monthly consumption of a KU residential customer). KU is proposing to withdraw Adjustment Clause TCJA from service and cancelling the associated billing credits effective when new base rates change. When the TCJA Surcredit is cancelled when new base rates take effect, the total monthly residential electric bill increase will be 11.7%, or approximately $13.47, for a customer using 1,139 kWh of electricity.

KU is proposing numerous revisions to the rates, terms and conditions for service under Pole and Structure Attachment Charges – Rate PSA, including expanding the availability of the schedule to internal communication network facilities of governmental units and educational institutions. If approved, the rates terms and conditions for attaching communication network facilities of such governmental units and educational institutions will be subject to Rate Schedule PSA.

KU is also proposing changes in the text of some of its rate schedules and other tariff provisions, including its terms and conditions for electric service. Complete copies of the proposed tariffs containing the proposed text changes and rates may be obtained by contacting, Kentucky Utilities Company at 220 West Main Street, Louisville, Kentucky, 40202, 1-800-981-0600, or by visiting KU's website at www.lge-ku.com.

Notice is further given that a person may examine this application at the offices of KU, 100 Quality Street, Lexington, Kentucky, and may also be examined at KU's website at www.lge-ku.com. A person may also examine this application at the Public Service Commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the commission's Web site at http://psc.ky.gov. A copy of the customer notice required by 807 KAR 5:001 Section 17 is posted and may be viewed in each public library located within KU's service territory or at the KU offices where bills are paid.

Comments regarding the application may be submitted to the Public Service Commission, by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, or by sending an email to the Commission's Public Information Officer at psc.info@ky.gov. All comments should reference Case No. 2018-00294.

The rates contained in this notice are the rates proposed by KU, but the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice. A person may submit a timely written request for intervention to the Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party. If the commission does not receive a written request for intervention within thirty (30) days of initial publication or mailing of the notice, the commission may take final action on the application.

A copy of the Notice of Filing and the proposed tariff, once filed, shall also be available for public inspection on KU's website at www.lge-ku.com, or through the Public Service Commission's website at http://psc.ky.gov.

Kentucky Utilities Company
c/o LG&E and KU Energy LLC
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40232
1-800-981-0600

Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602
502-564-3940

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(2)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

Notice of Intent. Utilities with gross annual revenues greater than $5,000,000 shall notify the Commission in writing of its intent to file a rate application at least thirty (30) days, but not more than sixty (60) days, prior to filing its application.

(a) The notice of intent shall state if the rate application will be supported by a historical test period or a fully forecasted test period.

(b) Upon filing the notice of intent, an application may be made to the commission for permission to use an abbreviated form of newspaper notice of proposed rate increases provided the notice includes a coupon that may be used to obtain a copy from the applicant of the full schedule of increases or rate changes.

(c) Upon filing the notice of intent with the commission, the applicant shall mail to the Attorney General's Office of Rate Intervention at a copy of the notice of intent or send by electronic mail in a portable document format, to rateintervention@ag.ky.gov.

Response:

See attached.

The Commission granted the request of KU and Louisville Gas and Electric Company ("LG&E") to publish an abbreviated newspaper customer notice.[3] Also, KU and LG&E are required to post the full customer notice in each public library located in the service territories.[4]

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[3] *Id.*
[4] *Id.*

a PPL company

Gwen R. Pinson
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
PO Box 615
Frankfort, Kentucky 40602-0615

Kentucky Utilities Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, KY 40232
www.lge-ku.com

Robert M. Conroy
Vice President
T 502-627-3324
F 502-217-4985
robert.conroy@lge-ku.com

August 27, 2018

RE: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates
Case No. 2018-00___

Dear Ms. Pinson:

Please take notice that Kentucky Utilities Company ("KU") intends to file on or after September 28, 2018, an application for a general adjustment in its electric rates, including changes to its electric tariffs. This application will be supported by a fully forecasted test period ending April 30, 2020.

KU has contemporaneously filed a Notice of Election of Use of Electronic Filing Procedures for this proceeding. 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,

Robert M. Conroy

cc: Rebecca W. Goodman, Esq.
Executive Director, Office of the Attorney General
Rate Intervention Division (via electronic mail)

a PPL company

Gwen R. Pinson
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
PO Box 615
Frankfort, Kentucky 40602-0615

Kentucky Utilities Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, KY 40232
www.lge-ku.com

Robert M. Conroy
Vice President
T 502-627-3324
F 502-217-4985
robert.conroy@lge-ku.com

August 27, 2018

RE: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates
Case No. 2018-00___

Dear Ms. Pinson:

Enclosed please find and accept a notice of election of use of electronic filing procedures in accordance with 807 KAR 5:001, Section 8. Kentucky Utilities Company intends to file on or after September 28, 2018, an application for a general adjustment in its electric rates, including changes to its electric tariffs.

Should you have any questions regarding the enclosed, please do not hesitate to contact me.

Sincerely,

Robert M. Conroy

cc: Rebecca W. Goodman, Esq.
Executive Director, Office of the Attorney General
Rate Intervention Division (via electronic mail)

NOTICE OF ELECTION OF USE OF ELECTRONIC FILING PROCEDURES

(Complete All Shaded Areas and Check Applicable Boxes)

In accordance with 807 KAR 5:001, Section 8, Kentucky Utilities Company gives notice of its intent to file an application for an adjustment of its electric rates with the Public Service Commission no later than September 28, 2018 and to use the electronic filing procedures set forth in that regulation.

Kentucky Utilities Company further states that:

	Statement	Yes	No
1.	It requests that the Public Service Commission assign a case number to the intended application and advise it of that number as soon as possible;	☒	☐
2.	It or its authorized representatives have registered with the Public Service Commission and are authorized to make electronic filings with the Public Service Commission;	☒	☐
3.	Neither it nor its authorized representatives have registered with the Public Service Commission for authorization to make electronic filings but will do so no later than seven days before the date of its filing of its application for rate adjustment;	☐	☒
4.	It or its authorized agents possess the facilities to receive electronic transmissions;	☒	☐

5. The following persons are authorized to make filings on its behalf and to receive electronic service of Public Service Commission orders and any pleadings filed by any party or the Public Service Commission Staff:

Name	Electronic Mail Address
Robert M. Conroy	robert.conroy@lge-ku.com
Allyson K. Sturgeon	allyson.sturgeon@lge-ku.com
Kendrick R. Riggs	kendrick.riggs@skofirm.com

	Statement	Yes	No
6.	It and its authorized representatives listed above have read and understand the procedures for electronic filing set forth in 807 KAR 5:001 and will fully comply with those procedures unless the Public Service Commission directs otherwise.	☒	☐

Signed [signature]

Name: Robert M. Conroy

Title: VP, State Regulation and Rates

Address: 220 West Main Street
Louisville, KY 40202

Telephone Number: 502-627-3324

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(6)(a)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

The financial data for the forecasted period shall be presented in the form of pro forma adjustments to the base period.

Response:

The financial data for the forecasted period is presented in the form of pro forma adjustments to the base period.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(6)(b)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

Forecasted adjustments shall be limited to the twelve (12) months immediately following the suspension period.

Response:

Forecasted adjustments have been limited to the twelve (12) months immediately following the suspension period.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(6)(c)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

Capitalization and net investment rate base shall be based on a thirteen (13) month average for the forecasted period.

Response:

Capitalization and net investment rate base are based on a thirteen (13) month average for the forecasted period.

Filing Requirement
807 KAR 5:001 Section 16(6)(d)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

After an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless the revisions reflect statutory or regulatory enactments that could not, with reasonable diligence, have been included in the forecast on the date it was filed. There shall be no revisions filed within thirty (30) days of a scheduled hearing on the rate application.

Response:

KU acknowledges this requirement.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(6)(e)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

The commission may require the utility to prepare an alternative forecast based on a reasonable number of changes in the variables, assumptions, and other factors used as the basis for the utility's forecast.

Response:

KU acknowledges this requirement.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(6)(f)
Sponsoring Witness: Christopher M. Garrett

Description of Filing Requirement:

The utility shall provide a reconciliation of the rate base and capital used to determine its revenue requirements.

Response:

See attached.

KENTUCKY UTILITIES COMPANY

Reconciliation of Capitalization and Rate Base

Line No.	Description	13 Month Average Total Company Balance	13 Month Average Kentucky Jurisdictional	13 Month Average Other Jurisdictional
1	Rate Base Percentage (Schedule J-1.1/J-1.2)		93.77%	6.23%
2	Capitalization:			
3	Common Equity	$ 3,001,947,921		
4	Long-Term Debt	2,607,964,904		
5	Short-Term Debt	70,738,410		
6	Subtotal	$ 5,680,651,235	$ 5,326,746,663	$ 353,904,572
7	Adjustments to Capitalization:			
8	Investment in EEI	(323,302)	(303,160)	(20,142)
9	Investment in OVEC and Other	(428,714)	(402,005)	(26,709)
10	Environmental Compliance Plans		(1,223,057,070)	-
11	Demand Side Management Plans		(3,848,544)	-
12	Subtotal	(752,016)	(1,227,610,780)	(46,851)
13				
14	Total Adjusted Capitalization (Schedule J-1.1/J-1.2)	$ 5,679,899,219	$ 4,099,135,883	$ 353,857,721
15				
16	Assets per books not included in rate base:			
17	Net ARO Assets		(48,022,822)	
18	Other Property and Investments	(24,735,681)	(23,194,648)	(1,541,033)
19	Cash and Temporary Investments	(5,247,997)	(4,921,047)	(326,950)
20	Accounts Receivable	(171,190,717)	(160,525,536)	(10,665,182)
21	Other Current Assets	(94,738,170)	(88,835,982)	(5,902,188)
22	Deferred Regulatory Assets	(203,164,633)	(190,507,477)	(12,657,157)
23	Other Deferred Debits	(36,187,462)	(33,932,983)	(2,254,479)
24	Subtotal	(535,264,660)	(549,940,494)	(33,346,988)
25				
26	Liabilities per books not included in rate base:			
27	Other Deferred Credits	-	-	-
28	Regulatory Liabilities	701,248,945	657,561,135	43,687,809
29	ARO Liabilities	165,695,113	155,372,308	10,322,806
30	Other Current Liabilities	217,924,069	204,347,399	13,576,669
31	Miscellaneous Long-Term Liabilities	18,947,981	17,767,521	1,180,459
32	Accumulated Provision for Pension & Postretirement	-	-	-
33	Bonds	(23,076,923)	(21,639,231)	(1,437,692)
34	Accumulated Deferred Income Taxes	(613,513,514)	(575,291,622)	(38,221,892)
35	Subtotal	467,225,669	438,117,510	29,108,159
36				
37	Items not included in rate base:			
38	Environmental Compliance Cash Working Capital		2,498,511	-
39				
40	Items included in rate base:			
41	Cash Working Capital (Income Statement)	61,495,178	52,552,424	6,444,243
42	Capitalization / Rate Base Allocation Differences	-	2,855,149	(2,855,149)
43	Subtotal	61,495,178	55,407,573	3,589,094
44				
45	Total Reconciliation	(6,543,813)	(53,916,900)	(649,735)
46				
47	Total Rate Base (Schedule B-1)	$ 5,673,355,406	$ 4,045,218,983	$ 353,207,986

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(a)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.

Response:

Please refer to the testimonies and exhibits of the following persons:

- Paul W. Thompson
- Kent W. Blake
- Lonnie E. Bellar
- David S. Sinclair
- Gregory J. Meiman
- Daniel K. Arbough
- Adrien M. McKenzie
- Christopher M. Garrett
- John J. Spanos
- Robert M. Conroy
- William Steven Seelye

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(b)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

The utility's most recent capital construction budget containing at a minimum a three (3) year forecast of construction expenditures.

Response:

See attached.

Kentucky Utilities Company
Case No. 2018-00294
Capital Expenditure Budget
Years 2018-2021

	Projected Capital Expenditures			
Category of Spend	**2018**	**2019**	**2020**	**2021**
Generation	344,377,549	288,900,165	168,061,775	154,269,292
Transmission	114,493,033	132,440,894	155,524,806	182,164,403
Distribution	129,654,787	144,947,972	131,461,058	133,395,251
Customer Services	19,226,207	15,617,060	15,677,343	19,329,940
IT & Other	27,374,886	28,285,751	32,473,502	27,937,189
Total	**635,126,462**	**610,191,842**	**503,198,484**	**517,096,074**

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(c)
Sponsoring Witnesses: Daniel K. Arbough / Lonnie E. Bellar / Kent W. Blake / David S. Sinclair

Description of Filing Requirement:

A complete description, which may be filed in written testimony form, of all factors used in preparing the utility's forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported.

Response:

A complete description of all factors used in preparing KU's forecast period, including the quantification, explanation and support for all econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels in KU's forecast period are contained in the written direct testimony of Daniel K. Arbough and David S. Sinclair filed with KU's application and are also otherwise quantified, explained and properly supported in the following documents attached to this Filing Schedule. All confidential information responsive to this request is being provided under seal pursuant to a Petition for Confidential Protection.

A. Financial Planning Modeling Process	Daniel K. Arbough
B. Electric Sales & Demand Forecast Process	David S. Sinclair
C. 2019 Business Plan Electric Sales Forecast	David S. Sinclair
D. [This line intentionally left blank.]	
E. Electric Class Load Profile Forecast Process	David S. Sinclair
F. [This line intentionally left blank.]	
G. Generation Forecast Process	David S. Sinclair
H. 2019 Business Plan Generation and OSS Forecast	David S. Sinclair
I. Line of Business Presentations	Lonnie E. Bellar / Kent W. Blake

Financial Planning Modeling Process

Table of Contents

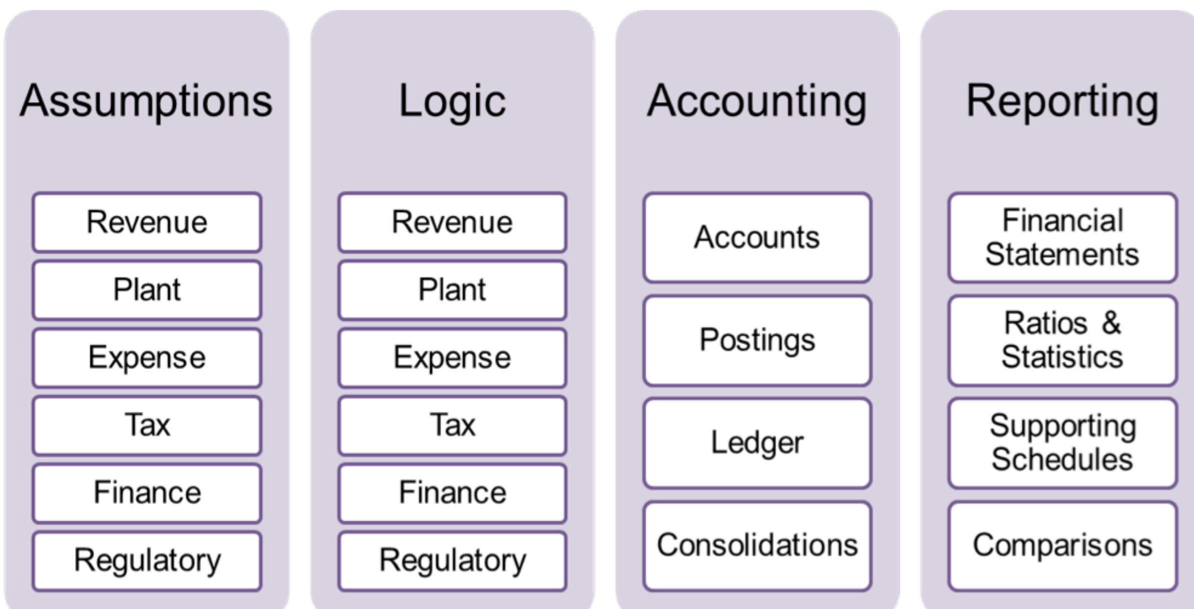
1. General

Introduction

The Financial Planning & Analysis group develops the five-year Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") and LG&E and KU Energy LLC ("LKE" or collectively "the Companies") business plan. The business plan is developed using the financial planning system, UIPlanner, an iterative model, which incorporates numerous inputs from the business as well as various formulas, algorithms and set logic. The business plan includes the projected five-year income statements, balance sheets and cash flows for the Companies.

UIPlanner (UI)

UI allows the Companies to manage all of the assumptions in the business plan, integrates the business logic, utilizes built-in accounting controls, and produces robust analyses and reports.



[1]

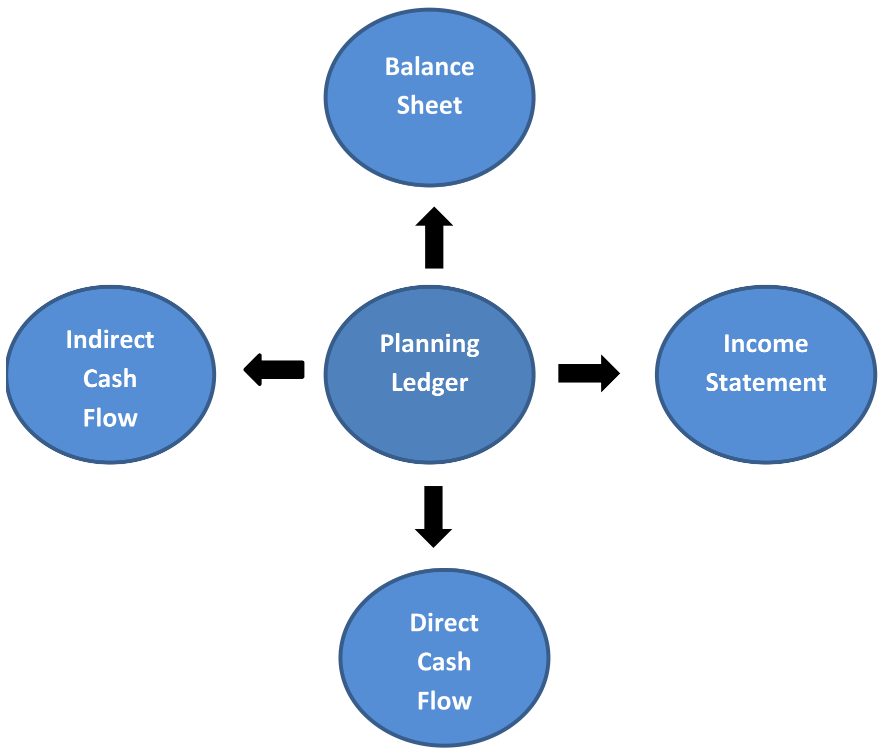
Planning assumptions are managed in UI. UI is superior to an Excel-based model because it allows for sharing assumptions in a common database. UI tracks changes to assumptions and maintains a record of who made the change and when.

UI has built-in accounting capabilities, which function identical to a general ledger (see Planning Ledger flow chart below). Double-entry accounting of debits and credits is

[1] http://utilitiesinternational.com/uiplanner-software/planning/

developed in UI to maintain integrity of financial statements. If a posting is not entered in UI or if one side of the debit/credit is missing, UI will produce an error message before it will produce a financial statement. Ledger accounts are organized with a configurable roll-up structure. UI also allows for combining several accounts to a summary account for consistent and concise formatting in the production of financial statements. These summary accounts are rolled up into a high-level area (asset, direct cash, expense, indirect cash, liability, or revenue). Each account in the ledger is also associated with an indirect cash flow account which can be customized to generate a detailed cash flow statement.

Planning Ledger Flow Chart



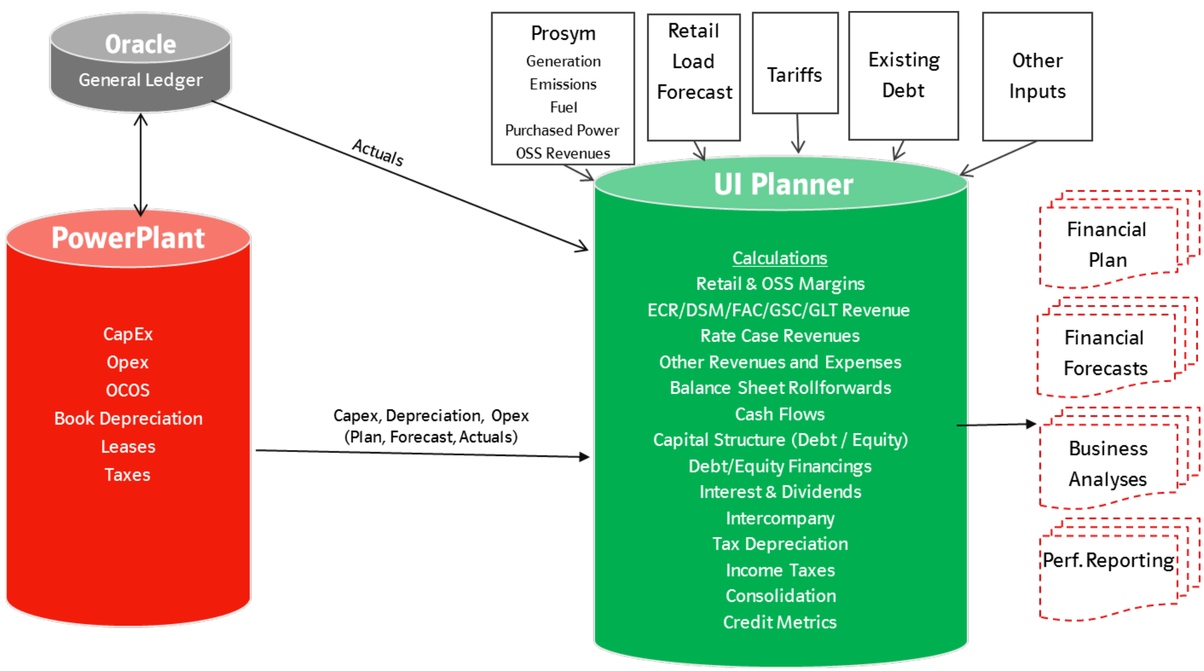
Each month actual balances are imported from the Oracle General Ledger (GL) to update UI with the latest balances and to compare the budget and revised forecast to actuals. The actuals imported into UI are compared to the trial balance in Oracle monthly to ensure completeness and accuracy.

Data in UI is entered into UI either manually or through a download from text files and housed within "cases". A collection of cases is grouped to create a "scenario". For example, the "2018 Business Plan" is a scenario in UI. After a scenario runs through the iterative process in UI, users can view the Financial Statements and other various reports in UI.

Security is specific by user in UI. When data assumptions are entered, the person entering the assumptions is tracked within UI for auditing purposes. Only certain users have the ability to edit data entry and logic assumptions. In addition, when a scenario, such as the business plan, is finalized, the scenario is locked so no further changes can be made. Only certain users have the ability to lock and unlock scenarios and cases. Logic from a case and/or scenario can be copied and utilized in additional what-if analyses. UI allows for creating and managing multiple scenarios with various planning assumptions and business logic in a transparent and efficient manner.

See the Financial Planning Software Flow Diagram below, detailing which systems provide data and other forms of inputs to UI to create the financial plan, forecast, business analysis and other management reports. This document summarizes the systems used to produce the business plan.

<u>Financial Planning Software Flow Diagram</u>



Budgeting Overview

LKE uses a "bottom up" budgeting approach. The process begins with the various business units preparing detailed budgets for their individual areas of responsibility, consisting of expense items, certain types of LOB managed revenues, and capital spending. The budgets prepared by the business units are reviewed and approved by LKE management. The LKE Officers ultimately approve the LKE consolidated annual budget. If any changes occur during the review and approval process, the changes are communicated to the appropriate line of business (LOB), and each LOB submits a revised budget through the same review and approval process.

Each year, LKE prepares a five-year forecast of operating revenues and expenses, which is the starting point for preparing the annual budget and the five-year business plan. Each business unit is required to create its own five-year capital and operation and maintenance (O&M) expense plan to produce an all-inclusive operating plan which is presented for review by the Officers. The five-year capital and O&M plan is developed and accumulated in PowerPlan, the Company's corporate budgeting application. These details from PowerPlan are uploaded into the financial planning system – UI.

2. Revenue and Load Forecast

Retail Revenue

In order to calculate revenues, UI logic uses the load forecast and the tariffs that need to be applied to the forecast. For energy, UI multiplies megawatt hours times the energy tariff. For demand, UI calculates base, intermediate and peak demand revenue by multiplying the megawatt or kilovolt-ampere (kVA) times the demand tariff for base, intermediate and peak demand. For customer charge revenue, UI multiplies the number of customers times the customer charge. For base fuel revenues, UI multiplies the base fuel rate times the megawatt hour sales by jurisdiction.

The first step in preparing the operating revenues is to obtain an energy, demand and customer forecast of the projected electric and gas sales. The load forecasts are calculated on a yearly basis for each tariff. See the Annual Electric Sales and Demand Forecast Process Document, the Annual Natural Gas Volume Forecast Process Document and associated presentations, for detailed descriptions of the assumptions and methodology used in developing the electricity and gas load forecast. The following information is uploaded into UI:

- Energy forecast for each month and year, by tariff
- Demand forecast by month and year, by tariff
- Customer count by month and year, by tariff
- Base fuel revenues forecast by month and year

Tariff rates are entered into UI based upon the tariff book currently in effect. UI then calculates energy, demand, and customer revenues by tariff. Allocators are used to convert the load from tariff rate to revenue class in UI. The allocators are supplied by the Sales Analysis and Forecasting group. The previous calendar year actuals data is utilized to calculate the allocators. The revenues are then posted to the income statement by revenue class.

Transmission Revenue

External Transmission revenue is imported into UI from an excel spreadsheet prepared by the Transmission Policy and Tariffs department. The projected external transmission amounts are calculated as follows:

1. Network Service (the forecast multiplied by the associated rates)
   a. The volumetric forecasts are provided by the customer by year.
   b. Volumetric forecasts are based on the summer and winter peaks provided and interpolated over a twelve month period.
   c. The transmission rates are forecasted based on Attachment O of the Open Access Transmission Tariff (OATT).
2. Point to Point Service (Service request multiplied by the associated rates)
   a. Long term service – is based on the original transmission request, these volumes remain fixed until their expiration unless there was newer information which indicated these long term reservations would be rolled over.
   b. Short-term firm service – is projected based on annual historical revenue.
   c. The transmission rates are forecasted based on Attachment O of the OATT.

The projected intercompany transmission revenue is imported into UI from PowerPlan based on the generation forecast provided by the Generation Planning department.

The transmission rates are documented in the LG&E and KU OATT, which is reviewed and approved by the FERC. The projected load is applied to the appropriate transmission rates to calculate the transmission revenue.

Miscellaneous Revenue

Miscellaneous revenue is comprised of:

- Forfeited discounts/late payment charges
- Reconnect, temporary service, unauthorized reconnect, gas meter and inspection charges and other service charges
- Rent from electric and gas property
- Other Electric and Gas revenues
- Refined coal reservation fees
- Electric vehicle charging station rental revenues

For most of the above items, the miscellaneous revenue is calculated by utilizing historical trends based on the most recent three years of data. Three years gives an appropriate distribution of data to evaluate the account activity. This data is then uploaded into UI based on the calculations done in Excel.

Accounts associated with cable TV attachments, rent from fiber optic, facility charges, and rent received from pole attachments, property, and equipment utilize the most recent year of data.

Refined coal exclusivity fees are fees received for allowing companies to reserve the right to locate refined coal facilities at Company generating stations.

Electric vehicle charging station rental revenues are based on budgeted EVSE-R electric vehicle charging station installations and monthly charging unit fees per existing tariffs.

3. Mechanisms

Background

The Kentucky Public Service Commission (KPSC) has adopted a series of regulatory mechanisms that reduce regulatory lag and provide for timely recovery of and a return on, in some instances, prudently incurred costs. The following represents an overview of certain key mechanisms and assumptions reflected in the business plan.

Environmental Cost Recovery (ECR)

The Utilities are entitled to recovery of operating costs and recovery of and a return on capital costs of complying with Federal Clean Air Act with a two-month lag. The first step is to calculate the total revenue requirement which involves determination of environmental rate base and operating expenses for each KPSC approved ECR project.

Within UI the revenue requirement for ECR is calculated using the following:

- The logic calculates a monthly ending rate base by adding ECR capital expenditures from the capital plan to the previous months' ending rate base; subtracting ECR depreciation for the period and increase/decrease in ECR deferred taxes calculated within UI. A return on the ending rate base is calculated using a weighted average cost of capital computed within UI using weighted average cost of debt and allowed return on equity;
- ECR Depreciation and O&M is then added to the return on rate base to calculate a total revenue requirement;
- A jurisdictional factor is computed within UI using a ratio of KY retail to total revenue and applied to the total revenue requirement to calculate a jurisdictionalized ECR Revenue Requirement;
- The model then deducts any ECR revenue recovered within the base rates to generate a net ECR mechanism revenue.

Demand Side Management (DSM)

DSM provides for concurrent recovery of DSM costs and provides incentive for implementing DSM programs, including lost revenue.

In UI, there are four components for DSM revenue:

- DSM expense as imported from PowerPlan within the Cost of Sales import
- DSM incentive revenue as calculated in UI on the eligible portion of programs
- DSM lost sales revenue as calculated in UI using the imported lost sales volume and rates from the DSM Energy Efficiency model
- DSM capital revenue requirement is calculated in UI by adding the capital spend imported from PowerPlan to the previous month's ending DSM rate base, adjusted for depreciation and the increase/decrease in deferred taxes. A return on the DSM rate base is calculated using a weighted average cost of capital computed within UI using weighted average cost of debt and allowed return on equity. In addition, the depreciation and O&M expenses are added to the return on the DSM rate base to calculate the total DSM Capital Revenue Requirement.
- DSM expense, incentive revenue, and lost sales revenues are added to the capital revenue requirement to calculate the total DSM revenue requirement.

Gas Line Tracker (GLT)

GLT provides for recovery of costs associated with replacing customer service risers, replacing and installing service lines, leak mitigation, main replacements, the steel gas service line program and the transmission pipeline modernization.

The GLT revenue requirement is calculated in UI using the following:

- The rate base is rolled forward for identified GLT projects using capital spend and in service dates per PowerPlan as well as the calculated deferred income taxes;
- The rate of return on rate base is computed within UI using weighted average cost of debt and allowed rate of return on equity.
- GLT Depreciation, Property Tax and O&M are then added to the return on rate base to calculate a total revenue requirement;

Fuel Adjustment Clause (FAC)

The FAC mechanism allows for near-real time recovery of allowed fuel expenses.

Total fuel expense incurred consists of all generation and purchased power costs. For FAC purposes, total recoverable fuel expense includes total incurred expense reduced by the following components: non-energy components of purchased power expense; substitute generation or purchased power costs during forced outages; coal burned for Off-System

Sales (OSS) electric generation, company use, line loss and unrecoverable intercompany sales. The total recoverable fuel expenses is then compared to the base fuel revenues. The over/under is booked to the FAC.

OSS

Included in a previous rate case settlement was an OSS Tracker which results in sharing the OSS margins on a 75 percent - 25 percent basis, with 75 percent of the OSS margins being credited to customers via the FAC.

Mechanism Revenue Calculations

For all mechanisms, except for the GLT, the total mechanism revenue requirement is divided by the total forecasted megawatt hours by electric rate code associated with each mechanism. These values are applied as a dollar per megawatt hour to calculate the revenue by electric rate code.

For GLT, the total mechanism revenue requirement is allocated to the customer class associated with GLT based on the class allocation percentages from the most recent filing.

The revenues from all mechanisms are recorded to the income statement as revenues from customers.

4. Generation Forecast and Other Cost of Sales (OCOS)

The PROSYM application is used to calculate generation and OSS. See the annual Plan Generation Forecast Process Document and related presentations, for a detailed description of the assumptions and methodology used to calculate these inputs.

The projected data includes fuel burn, generation, purchase power, emissions, and OSS levels from an hourly dispatch model. Imported into UI is a monthly, by unit, volumes, revenues and costs associated with off system sales, purchased power, emissions, generation, and fuel burn for the planning period.

Power Purchase Agreement

Power purchase agreement costs are based on the contracts set with the third party power producers. The amounts per the contracts are imported into UI, which is recorded on the income statement as the purchased power cost. The information uploaded into UI by month and year includes the following costs:

- Capacity and demand payments
- Energy payments, and
- Firm gas transport costs, if applicable

UI logic ensures the power purchase cost reflects the recovery of the energy and firm gas transport costs through the FAC and the capacity and demand costs through base rates.

Other Cost of sales (OCOS)

OCOS inputs come from PowerPlan and PROSYM. OSS, purchased power, and fuel related costs come from PROSYM, as noted above. Emissions, mechanism (DSM, ECR, ECR, Gas Supply Clause, and GLT), and transmission related costs come from PowerPlan.

OCOS includes variable production consumables used by the power plants in the generation of electricity. For coal generating units, this includes the cost of operating environmental controls and the cost of controlling coal combustion residuals (CCR). This includes:

- Limestone – SO_2 emission control for flue gas desulfurization (FGD) systems
- Ammonia – NO_X emission control for selective catalytic reduction (SCR) systems
- Hydrated Lime – SO_3 emission control for sorbent injection systems
- Powder Activated Carbon – Hg emission control for pulse jet fabric filter systems

The individual power plant's budget coordinator, in coordination with the operations leadership team at the plant, calculates the costs. This is a function of the usage rates for the consumables utilized by each individual operating unit. This is multiplied by the unit price determined by fleet wide contracts with suppliers. Planned outages and forecasted generation levels by year are included in these assumptions for each unit.

The calculation for these consumables includes the following inputs and calculations:

Unit Price	Usage Rate	Unit Production	Conversion	Total Projected Cost
$/ton (lbs.)	lbs. /hour	MWH's by unit	$/MWH	Total $ by month and year

These costs are loaded into PowerPlan under the appropriate FERC account and then uploaded into UI and incorporated into the Income Statement.

The cost of sales items related to fuel burn, emissions and purchased power are reflected in the Cost of Electric Sales section of the Income Statement.

Gas Supply

Gas supply costs are calculated by using the gas load forecast priced out at contracted rates and market prices for open/indexed positions.

5. Operations & Maintenance (O&M) (Non-fuel)

O&M expenses are included as part of the Income Statement and reflect the labor and non-labor expenditures incurred and charged to the appropriate FERC account and company location. The budget is developed in a "bottoms up" approach and is reviewed and approved by several levels of management before being entered into PowerPlan for consolidation. This information is then uploaded to UI.

Labor Cost

The Company's current labor base is obtained from PeopleSoft annually in March. The PeopleSoft data is exported to excel where the wage increases, vacation hours, personal days, and sick time are manually added. The adjusted data is imported into PowerPlan with the labor forecast being available by mid-March. The forecast includes full-time and part-time regular employees, summarized by employee type and expenditure organization.

Updates to the forecast in PowerPlan are due in early April. This updated data is used to calculate employee benefit costs (also referred to as 'burdens' - which include costs such as pension, savings plan, medical, dental, and payroll taxes), which will be added to the forecast by mid-April. The labor forecast is not finalized at this time and changes can be made, as required.

Non-labor Expenses

The management teams and budget coordinators throughout the LOBs prepare the budget for non-labor O&M expenses at the same time as the labor budget. These expenses are budgeted to the appropriate FERC account in PowerPlan.

Planned changes in costs within accounts can be specifically escalated according to contractual changes and other volume based assumptions or expected changes in primary cost categories such as generation facilities, outages, workforce plan changes, demand-side management, and environmental costs.

- The labor rates are subject to possible adjustment pursuant to union negotiations. The rate increase assumptions are based on annual benchmarking studies performed.
- Non-labor expenses are increased at known cost increases due to contract language, fixed amounts, or historical trend increases in costs. Non-labor expenses do not contain a general inflationary increase.

6. Property Tax

Property taxes are estimated annually based on net book asset values, including CWIP, as of December 31 of the previous year and include several current asset balances such as; fuel inventory and materials and supplies. The expense accrual is spread evenly over twelve months while cash payments are based on historic trends, which normally result in large cash payments during the fourth quarter of a calendar year.

The primary source of data used to calculate the estimates is within the UI report labeled "KY Plant Account". The plant account assignment determines the property classification (real estate, manufacturing machinery, other tangible) and then the appropriate tax rates are applied to those balances. State and local tax rates are based on prior year settlements with an assumed increase to local tax rates of two percent per year.

7. Other Income Statement Items

Other income and expense items not included above include:

- Donations – annual budget is approved by Senior Officers based on planned commitments and in support of Community and Corporate Responsibility initiatives
- Employee Recognition costs (non-safety related) – based on detailed review of historical and projected expenses for employee recognition programs under each business unit
- Non-Utility Revenues and Expenses – based on detailed review of historical and projected items, including contractual based amounts and projected increases
- Interest income and dividends received – primarily interest received which is based on the interest income from temporary cash investments. The interest rate is obtained from the Corporate Finance department and UI calculates the monthly expected interest income based on the temporary cash investment balance.

8. Taxes

Current and Deferred Income Taxes

Income taxes are calculated using several schedules within UI. The calculation starts by utilizing the monthly pretax book income per UI's income statement. Pretax book income is then adjusted by permanent and temporary book/tax differences to derive taxable income. The book/tax differences are primarily pulled from multiple sources within UI, which include;

- tax depreciation,
- book depreciation,
- regulatory asset & liability movement,

- pensions/post-retirements, and
- capitalized interest

Other book/tax differences are manually input into UI. Taxable income is multiplied by the statutory tax rates to determine current tax expense. Quarterly tax payments are derived based on current tax expense.

Deferred taxes are calculated within UI by using the temporary book/tax differences used in the current tax calculation and applying the statutory tax rates. Adjustments to deferred tax expense are made for excess deferred taxes, investment tax credit (ITC) amortizations, and ITC basis reductions as provided by the Tax department. Additionally, regulatory tax movements are manually entered into UI based on schedules maintained by the Tax department.

9. Capital / Utility Plant

Background

Each LOB develops a five-year Capital plan by individual project that includes the start date, the timing of expected spend projections and the in service date for each project. The Capital plan is entered and maintained in PowerPlan.

The Senior Officers approve the Capital plan each year. The Capital plan is presented to the Senior Officers for approval by a subcommittee referred to as the Resource Allocation Committee ("RAC"). The RAC includes leaders from multiple LOBs so that Capital decisions are made based on priorities of the company as a whole.

In order to import the capital budget into UI, Financial Planning receives an excel file from PowerPlan containing monthly capital construction expenditures (CWIP) and cost of removal (RWIP) by utility. There are categories in the model used to separate mechanism capital (ECR, DSM, GLT) from non-mechanism capital.

10. Closings to Plant in Service and Depreciation

After capital spending is booked to CWIP on the balance sheet, UI gets an import from PowerPlan by plant account to determine additions to Plant in Service.

UI also imports a depreciation forecast that is done based on the Capital plan, including property classifications and in service dates, and approved depreciation rates.

The approved depreciation rates[2] are from the latest depreciation study, which are broken into life, salvage, and cost of removal per depreciation group. The rates are annual, so they are divided by 12 and multiplied by the monthly plant in service ending balances. The

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[2] Filed rates based on most recent depreciation study to be approved by the KPSC.

depreciation group to which an asset belongs is determined by the location and plant account selected at the time the capital project is setup in PowerPlan.

The Plant in Service ending balance for the most recent month of actuals is pulled out of PowerPlan. The ending balance of each forecast month is calculated as the beginning Plant in Service balance plus any capital additions placed in service for the month minus any asset retirements for the month. We use a half-month convention for additions and retirements. In the first month of an addition or retirement to Plant in service, we divide the normal depreciation amount by two. This is done to average out the spend since the addition or retirement does not always occur on day one of the month.

The additions to Plant in Service are based on the Capital plan and the estimated in-service dates on those assets. If the asset is already in service and additional money is spent on the asset, the spend is put in Plant in Service in that same month of spend. If the asset is not yet in service and spend occurs, it is held in CWIP until the month of the estimated in-service date in PowerPlan, on which date the entire CWIP balance is moved to plant in service.

11. Dividends, Debt and Equity

Dividends:

LG&E and KU (the “Utilities”) pay dividends to its parent, LKE, on a quarterly basis. The dividend has historically been calculated in the model using a payout assumption equal to 65 percent of the previous quarter’s net income. This percentage may be revised to maintain a balanced capital structure. Equity contributions from the parent may also be received by LG&E and KU to maintain the desired capital structure. These payout ratios may change over time.

To maintain the desired capital structure at LG&E and KU (53% equity/47% debt), LKE makes equity contributions to the Utilities or the Utilities pay extra dividends to LKE. At any time where the Utilities can pay dividends in excess of 65 percent, that amount is paid to LKE, who in turn utilizes the additional cash to pay down the intercompany Note Payable to PPL. If LKE needs funds to provide equity contributions to the Utilities, LKE either receives equity contributions from PPL or borrows intercompany debt from PPL.

Capital Structure:

LG&E and KU strive to maintain a ratio of 53% equity and 47% debt. Within UI, the debt balancing and equity ratio targeting logic is different on the quarter versus non-quarter months. Equity ratio targeting reviews the capitalization ratios and rebalances it every quarter to 53% equity and 47% debt. LKE serves as the medium to move cash from the Utilities to parent or from the parent to the Utilities to maintain this ratio. Cash balancing logic looks at the cash needs and calculates how to fund those needs. It is important to note that UI limits cash balances at the Utilities to $5 million unless short-term debt is zero and there is positive cash flow from operating and investing operations.

The following information is entered into UI for each individual long-term debt issuance:

- company,
- issue date,
- interest rate,
- first interest payment date,
- issue amount, and
- retirement date

These debt issuance properties are entered and maintained in UI under the Edit Attributes module. The attributes in the Business Plan are compiled to create a case, which is used to run the Business Plan scenario.

On the non-quarter months, UI calculates cash needs from operating and investing operations and issues debt equal to cash shortage. Short-term debt in the form of commercial paper is issued first until it reaches a maximum as prescribed by the Corporate Finance department (typically $300 million by Utility). The Utilities each have approved commercial paper programs of $350 million and FERC has approved short-term debt of up to $500 million for each utility. However, the Utilities need to maintain liquidity for emergencies and to support certain floating rate tax-exempt bonds. Therefore, the Utilities have a general modeling limit of $300 million on the commercial paper balances. The maximum can be changed after discussions with the Treasurer and the CFO. Once the maximum short-term debt is reached, long-term debt is issued in increments of $300 million or more and the balancing starts again the next month. The $300 million minimum is used because at that size the bonds are index-eligible and more attractive to investors, which results in a lower interest rate.

On the quarter months, the model balances equity and debt to a 53:47 ratio over multiple iterations. While performing the debt to equity targeting, UI issues only short-term debt to fund cash needs from operating and investing activities. The model is monitored to make sure that short-term debt balances are always within the acceptable limits. Similarly, to the non-quarter months, once the maximum short-term debt is reached, long-term debt is issued in increments of $300 million or more. Capital contributions in the form of equity from LKE are used to maintain the proper equity to debt ratios. LKE receives capital contributions from PPL to fund the Utilities cash needs.

All short-term interest rates on cash balances are based on a spread to the one-month LIBOR. The spread is based on current market issuances for similarly rated companies. For long-term debt, the rates are based on a spread to the US treasury rates (five-year, ten-year, thirty-year, etc.). The long-term debt spreads are also based on current levels for similarly rated entities and projected changes in those spreads for forecast periods. The forward curve as of a selected date is used to determine future LIBOR and US treasury rates.

12. Pension & Postretirement

Plan assumptions are evaluated by Senior Financial officers and Human Resources associates and the independent actuary. These assumptions are approved on an annual basis, barring any events requiring an interim re-measurement.

During the first half of the year, the independent actuary delivers a projection of estimated Plan funding, pension expense and pension liability for the five-year Business Plan based on management's assumptions. These assumptions include the annual discount rate, the expected return on plan assets, the expected annual wage increase, the annual mortality rate table, funding policy and other assumptions as needed. The actuary's projections also incorporate the 15-year amortization of gains and losses as agreed in the 2014/2015 Kentucky rate case.

The projected pension and postretirement costs received from the actuary such as the service cost, interest cost, return on plan assets, and amortizations of prior service cost, transition, and (gain)/loss are summarized by company and by program offering. These amounts are used to update the annual budget by reflecting changes to the balance sheet for the revised liability projections and the pension cost used when calculating the employee burden rates by company. The pension burden rates are included in the O&M and Capital budgets entered into PowerPlan. These amounts are spread by month consistent with the timing of the labor budget.

Pension funding is assumed to occur annually in January while postretirement funding is assumed quarterly with the 401(h) portion of the funding occurring all in the second quarter.

13. Other Balance Sheet assumptions

a. Balances

The last actual monthly balances from the Balance Sheets were the starting points for this forecast (for this budget it was June). The amounts were imported to UI from the G/L. A detailed and thorough balancing process is also done to ensure all details from Oracle translate appropriately into UI.

b. Leases

Beginning January 1, 2019 upon the adoption of Accounting Standards Codification (ASC) 842 Leases, all leases will be recorded on the balance sheet. The monthly balance sheet amounts are obtained from the lease report obtained from the Financial Accounting and Analysis department using the PowerPlan Lease module and this is uploaded into UI from a text file.

c. Cash

As noted above, minimum cash balances are set each year at $5 million per utility. This is based on discussion with Corporate Finance and if UI determines insufficient cash balances based on the projected activity short-term debt is issued.

d. Accounts Receivable and Unbilled Revenue

The monthly balances are based on forecasted revenues from customers and projected days of sales in receivables based on historical trends.

e. Fuels, materials and supplies (M&S)

Fuel inventory balances are developed based on targeted inventory levels for each generation plant. PROSYM is utilized to determine the amount of purchases needed to achieve the targeted inventory levels. Price assumptions for coal purchases utilize existing contract information as well as the assumed cost of coal that will be contracted in the future.

Natural Gas Inventory: Storage inventory levels are set within storage operating parameters in order to achieve maximum deliverability needed to meet winter season requirements. Price assumptions for gas purchases reflect forecasted gas prices and estimated pipeline transport costs. Materials and supplies inventory is based on the annual June balance and is adjusted for disposals.

f. Prepayments affecting the balance sheet include insurance, Information Technology (IT) contracts, Kentucky Public Service Commission Fees (PSC), and Tennessee Valley Authority (TVA) fees. For insurance, the amortization of the balance/expense begins at the start of the policy and continues through the term of the policy. For IT contracts, the estimated balances are amortized monthly over the period of services. For the PSC and TVA fees, we receive a bill for the current year. The out years of the budget are escalated at an appropriate rate and the yearly cost is amortized over twelve months.

g. Unamortized debt expenses

For each bond issued, the Company incurs debt issuance costs, which are amortized over the period required by GAAP, generally the life of the debt issued. Additional financing costs that require amortization are unamortized loss on reacquired or remarketed debt, which is the expense that remains to be amortized when a debt instrument is remarketed/ refinanced / repurchased. The financing costs are amortized over the life of the replacement debt. Amortized financing costs are provided by Corporate Finance for future periods and input into UI. The amortization expense flows to the income statement under interest expense. The unamortized financing costs are found on the balance sheet under other non-current assets and the unamortized loss on reacquired or remarketed debt are found on the balance sheet under regulatory assets.

h. Regulatory Assets and Liabilities

Adjustments to the regulatory assets and liabilities are obtained from schedules produced by the Company's Regulatory Accounting Department, reflecting amortization rates previously approved by the Commission on existing line items and line of business proponent estimates for proposed line items. These schedules include storm costs, rate case expenses, deferred income taxes, CCR Asset Retirement Obligation (ARO) recovery, etc.

Unrecognized pension and post-retirement costs are amortized as part of the monthly expense projections discussed earlier.

UI performs calculations for regulatory assets and liabilities associated with the various rate mechanisms to address regulatory lag issues and under/over recoveries. The amortization of interest rate swap regulatory assets and liabilities are performed using UI logic.

i. ARO

The calculation of accretion expense is performed in an automated fashion within the PowerPlan Fixed Asset System. Accretion and depreciation expense are calculated by taking the beginning ARO liability balance multiplied by the discount rate / depreciation rate for each ARO. The ARO depreciation and accretion are recorded onto the income statement and then reclassified back into the balance sheet as a regulatory asset.

j. Accounts Payable

The material monthly balances are based on a lag utilizing capital spend and operation and maintenance expense monthly totals. Actual payables range from 15 days to 45 days from invoice date, the budget utilizes 50% of the current month and 50% of the prior month as it relates to capital spend and operation and maintenance expense monthly totals.

Electric Sales & Demand Forecast Process

PPL companies

Sales Analysis & Forecasting
September 2018

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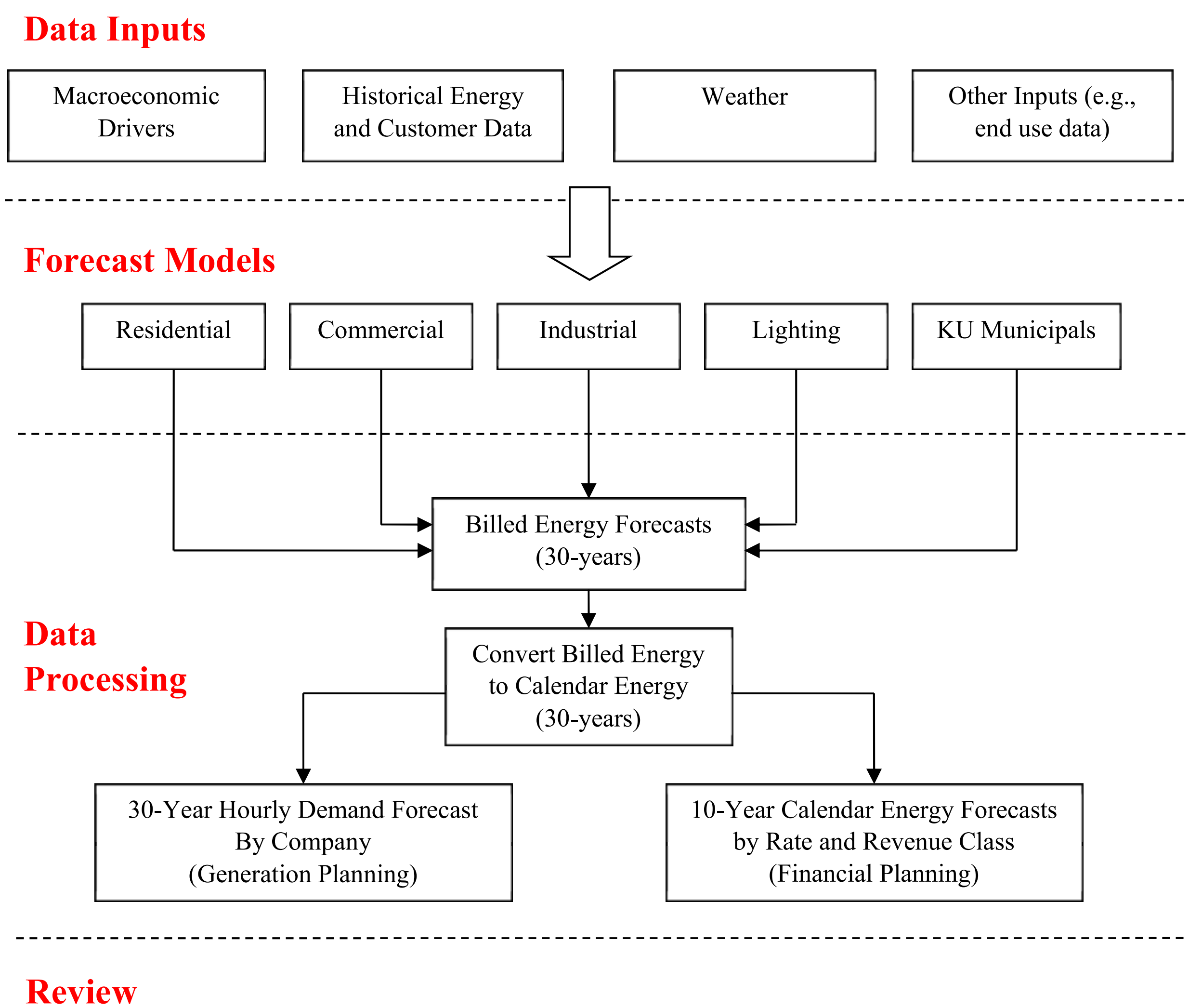
1. Introduction

The Sales Analysis & Forecasting group develops the sales and demand forecasts for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies"). These forecasts serve as foundational inputs for the Generation Planning department's Generation Forecast and the Financial Planning department's Business Plan. This document summarizes the processes used to produce the sales and demand forecasts. The forecast process can be divided into four parts (see Figure 1).

Figure 1 – Load Forecasting Process Diagram



The first part of the forecast process involves gathering and processing input data. The following are key inputs to the forecast process:

- Macroeconomic data
- Historical energy and customer data
- Weather data (20-year normal degree-day series)

- Other data, including billing portion forecasts, class-level electricity price series, and residential appliance shares and efficiencies.

The input data is used to specify a number of forecast models for each company. Generally, each model is used to forecast energy sales for a group of customers with homogeneous energy-use patterns within the same, or similar, tariff rates.

Most of the forecast models produce monthly energy forecasts on a billed basis.[1] In the third part of the forecast process, the billed energy forecasts are allocated to calendar months and then to rate and revenue classes for the Financial Planning department.[2] In addition, a forecast of hourly energy requirements is developed for the Generation Planning department.[3]

The final part of the forecast process includes validating and documenting the forecast results. To ensure results are reasonable, the new forecast is compared to (i) the previous forecast and (ii) weather-normalized actual sales for the comparable period in prior years.

Each of these steps and the software tools used to produce the forecast are discussed in more detail in the following sections.

2. Software Tools

The following software packages are used in the forecast process:

- SAS, R
- Metrix ND (Itron)
- Microsoft Office: Excel, PowerPoint, Access
- @Risk

SAS, R, and Metrix ND are used to specify forecast models. The Microsoft Office tools are primarily used for analysis and presentations. Finally, @Risk is used to assess the reasonableness of the forecast.

[1] All customers are assigned to one of 20 billing portions. A billing portion determines what time of the month a customer's meter is read. Because the beginning and end of most billing portions do not coincide with the beginning and end of calendar months, most customers' monthly bills will include energy that was consumed in multiple calendar months. The energy on customers' bills is referred to as "billed" energy.
[2] Rate class defines the tariff assigned to each customer meter while Revenue class is a higher level grouping; a Revenue class consists of one or more rate classes.
[3] Energy requirements are equal to sales plus transmission and distribution losses.

3. Input Data

Table 1 provides a summary of data inputs. The sections that follow describe key processes used to prepare the data for use in the forecast process.

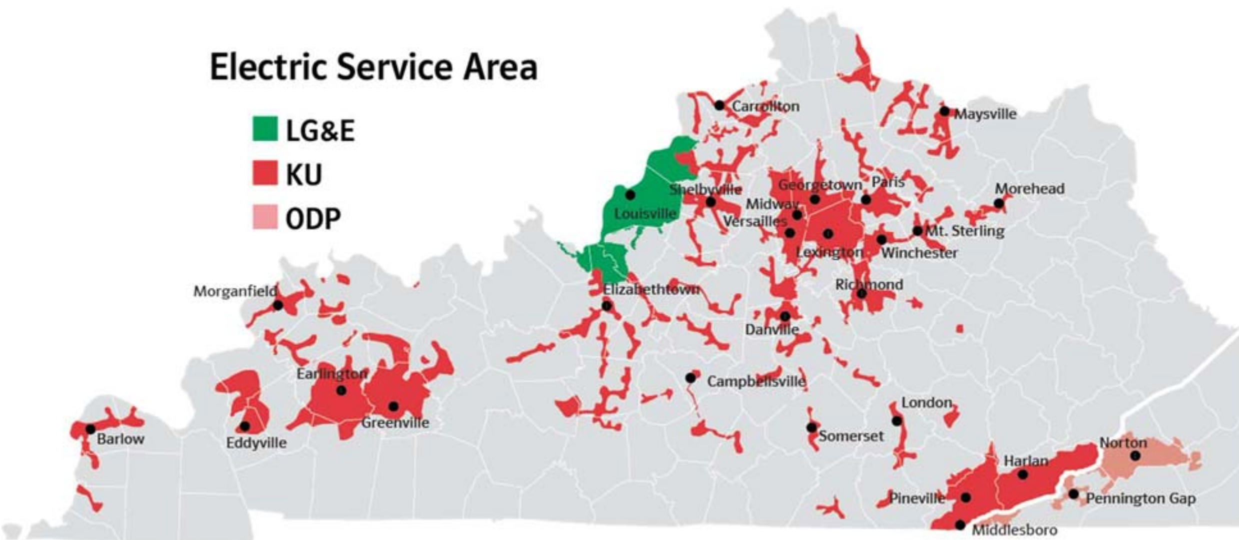
Table 1 – Summary of Forecast Data Inputs

Data	***Source***	***Format***
State Macroeconomic and Demographic Drivers (e.g., Employment, Wages, Households, Population)	IHS Markit, Kentucky Data Center	Annual or Quarterly by County – History and Forecast
National Macroeconomic Drivers	IHS Markit	Annual or Quarterly – History and Forecast
Personal Income	IHS Markit	Annual by County
Weather	National Oceanic and Atmospheric Administration (“NOAA”)	Daily HDD/CDD Data and Hourly Solar Irradiance by Weather Station – History
Billing Portion Schedule	Revenue Accounting	Monthly Collection Dates – History and Forecast
Appliance Saturations/Efficiencies	Energy Information Administration (“EIA”), 2010 LG&E/KU Residential Customer Survey	Annual – History and Forecast
Structural Variables (e.g., dwelling size, age, and type)	EIA, 2010 LG&E/KU Residential Customer Survey	Annual – History and Forecast
Elasticities of Demand	EIA / Historical Trend	Annual – History
Billed Sales History	CCS Billing System	Monthly by Service Territory and Rate Group
Number of Customers History	CCS Billing System	Monthly by Service Territory and Rate Group
Energy Requirements History	Energy Management System (“EMS”)	Hourly Energy Requirements by Company
Annual Loss Factors	2012 Loss Factor Study (by Management Applications Consulting, Inc.)	Annual Average Loss Factors by Company
Solar Installations	CCS Billing System, National Renewable Energy Laboratory (“NREL”)	Net Metering/Qualifying Facility Customers, Solar Net Metering Customer Forecast
Electric Vehicles	IHS Markit, Bloomberg New Energy Finance (“BNEF”), NREL, Electric Power Research Institute (“EPRI”)	Monthly Cars on Road (historical), Monthly Cars on Road (forecast), Hourly EV Charging Shapes

3.1 Service Territory-Specific Macroeconomic Forecasts

IHS Markit produces forecasts of macroeconomic drivers by county. With an understanding of the counties that make up each service territory, this data can be used to create service territory-specific forecasts of macroeconomic drivers. Figure 2 contains a map of the LG&E, KU, and ODP electric service territories.

Figure 2 – LG&E, KU, and ODP Service Territory Map



LG&E serves customers in Louisville and 16 surrounding counties. KU serves customers in 77 Kentucky counties and five counties in Virginia, where KU operates under the name Old Dominion Power Company ("ODP"). For the purposes of this document, the area served by KU in Kentucky is called the KU service territory; the area served by KU in Virginia is called the ODP service territory. Service territory-specific macroeconomic forecasts are created by aggregating the applicable county-specific forecasts for the counties in the LG&E, KU, and ODP service territories.

3.2 Processing of Weather Data

Weather is a key explanatory variable in the electric forecast models. The weather dataset from NOAA's National Climatic Data Center ("NCDC") contains temperature (maximum, minimum, and average), heating degree days ("HDD"), and cooling degree days ("CDD") for each day and weather station over the past 20+ years. This data is used to create (a) a historical weather series by billing month, (b) a forecast of "normal" weather by billing month, and (c) a forecast of "normal" daily weather.[4] Each of these processes is summarized below.

[4] "Normal" weather is defined as the average weather over a 20-year historical period. The Companies do not attempt to forecast any trends in weather.

3.2.1 Historical Weather by Billing Month

The process used to create the historical weather series by billing month consists of the following steps:

1. Using the historical daily weather data from the NCDC, sum the HDD and CDD values by billing portion.[5] Each historical billing month consists of 20 portions. The Companies' historical meter reading schedule contains the beginning and ending date for each billing portion.
2. Average the billing portion total HDDs and CDDs by billing month.

3.2.2 Normal Weather Forecast by Billing Month

The process used to produce the forecast of normal weather by billing month includes the production of a daily forecast of normal weather. The process used to develop the daily forecast (summarized below in Steps 2-5) is consistent with the process used by the NCDC to create its daily normal weather forecast.[6] The following steps are used to create the forecast of normal weather by billing month:

1. Compute the forecast of normal monthly weather by *calendar* month by averaging monthly degree-day values over the period of history upon which the normal forecast is based. The normal weather forecast is based on the most recent 20-year historical period. Therefore, the normal HDD value for January is the average of the 20 January HDD values in this period.
2. Compute "unsmoothed" daily normal weather values by averaging temperature, HDDs, and CDDs by calendar day. The unsmoothed normal temperature for January 1, for example, is computed as the average of the 20 January 1 temperatures in the historical period. This process excludes February 29.
3. Smooth the daily values using a 30-day moving average centered on the desired day. The "smoothed" normal temperature for January 1, for example, is computed as the average of the unsmoothed daily normal temperatures between December 16 and January 15.
4. Manually adjust the integer values in Step 3 so that the following criteria are met:
    a. The monthly average temperature – computed by averaging the daily temperatures by month and rounding to the nearest integer – should match the normal monthly temperatures in Step 1.
    b. The sum of the daily HDDs and CDDs by month should match the normal monthly HDDs and CDDs in Step 1.
    c. The daily temperatures and CDDs should be monotonically increasing from winter to summer and monotonically decreasing from summer to winter. The daily HDD series should follow a reverse trend.

   These criteria ensure the daily normal series is consistent with the monthly normal series.
5. The Companies' forecasted meter reading schedule contains the beginning and ending date for each billing portion through the end of the forecast period. In this step, sum the HDD

[5] Weather data in the electric forecast is taken from the weather stations at the Bowman Field Airport in Louisville, Bluegrass Field Airport in Lexington, and Tri-Cities Airport in Tennessee.
[6] The NCDC derives daily normal values by applying a cubic spline to a specially prepared series of the monthly normal values.

and CDD values by billing portion. Use the February 28 weather data as a proxy for February 29 when billing portions include leap days.

6. Average the billing portion totals by billing month.

4. Forecast Models

LG&E and KU's electricity sales forecasts are developed through econometric modeling of energy sales by rate class, but also incorporate specific intelligence on the prospective energy requirements of the utilities' largest customers. Econometric modeling captures the (observed) statistical relationship between energy consumption – the dependent variable – and one or more independent explanatory variables such as the number of households or the level of economic activity in the service territory. Forecasts of electricity sales are then derived from a projection of the independent variable(s).

This widely-accepted approach can readily accommodate the influences of national, regional and local (service territory) drivers of electricity sales. This approach may be applied to forecast the number of customers, energy sales, or use-per-customer. The statistical relationships will vary depending upon the jurisdiction being modeled and the class of service.

The LG&E sales forecast comprises one jurisdiction: Kentucky-retail. The KU sales forecast comprises three jurisdictions: Kentucky-retail, Virginia-retail, and FERC-wholesale.[7] Within the retail jurisdictions, the forecast typically distinguishes several classes of customers including residential, commercial, public authority, and industrial.

The econometric models used to produce the forecast pass two critical tests. First, the explanatory variables of the models must be theoretically appropriate and widely used in electricity sales forecasting. Second, the inclusion of these explanatory variables must produce statistically-significant results that lead to an intuitively reasonable forecast. In other words, the models must be theoretically and empirically robust to explain the historical behavior of the Companies' customers. These forecast models are discussed in detail in the following sections.

4.1 Residential Forecasts

The Companies develop a residential forecast for each service territory. For the KU and LG&E service territories, the residential forecast includes all customers on the Residential Service ("RS"), Residential Time of Day ("RTOD"), and Volunteer Fire Department ("VFD") rate schedules. The ODP Residential forecast includes all customers on the RS rate schedule.[8] Residential sales are forecasted for each service territory as the product of a customer forecast and a use-per-customer forecast.

[7] For the purposes of this document, the KU service territory comprises KU's Kentucky-retail and FERC-wholesale jurisdictions. The ODP service territory comprises the Virginia-retail jurisdiction.

[8] KU's Virginia-retail jurisdiction does not have RTOD or VFD rate schedules.

4.1.1 Residential Customer Forecasts

The number of residential customers is forecasted by service territory as a function of the number of forecasted households or forecasted population in the service territory. Household and population data by county and Metropolitan Statistical Area ("MSA") is available from IHS Markit and the Kentucky Data Center.

4.1.2 Residential Use-per-Customer Forecasts

Average use-per-customer is forecast using a Statistically-Adjusted End-Use ("SAE") Model. The SAE model combines econometric modeling with traditional end-use modeling. The SAE approach defines energy use as a function of energy used by heating equipment, cooling equipment, and other equipment.

$$\text{Use-per-Customer} = a1*XHeat + a2*XCool + a3*XOther$$

Inputs for developing the heating, cooling, and other variables include weather (heating and cooling degree days), appliance saturations, efficiencies, and economic and demographic variables such as income, population, members per household and electricity prices. Once the historical profile of these explanatory variables has been established, a regression model is specified to identify the statistical relationship between changes in these variables and changes in the dependent variable, use-per-customer. A more detailed discussion of each of these components and the methodology used to develop them is contained in Appendix A.

4.2 Commercial and Industrial Forecasts

Table 2 lists the rate schedules included in the commercial and industrial forecasts. A relatively small number of the Companies' largest industrial customers account for a significant portion of total industrial sales, and any expansion or reduction in operations by these customers can significantly impact the Companies' load forecast. As a result, sales to these customers are forecast based on information obtained through direct discussions with these customers. These regular communications allow the Companies to directly adjust sales expectations given the first-hand knowledge of the utilization outlook for these companies. The following sections summarize the Companies' commercial and industrial forecasts.

Table 2: Commercial and Industrial Rate Schedules

Service Territory	Rate Schedules
LG&E	General Service ("GS"), Power Service ("PS"), Retail Transmission Service ("RTS"), Time-of-Day Primary Service ("TODP"), Time-of-Day Secondary Service ("TODS")
KU	All-Electric School ("AES"), Fluctuating Load Service ("FLS"), GS, PS, RTS, TODP, TODS
ODP	GS, PS, RTS, TODP, TODS, Water Pumping Service ("M")

4.2.1 General Service Forecasts

The general service forecasts include all customers on the GS rate schedule. For each service territory, the GS sales forecast employs an SAE model similar to the model used to forecast residential use-per-customer, and defines energy use as a function of energy used by heating equipment, cooling equipment, and other equipment as well as binary variables to account for anomalies in the historical data. A more detailed discussion of this model is included in Appendix B.

4.2.2 KU Secondary Forecast

The KU Secondary forecast includes all customers who receive secondary service on the PS rate schedule and all customers on the TODS rate schedule. Sales to these customers are modeled as a function of heating and cooling degree days, cooling efficiencies, and binary variables which account for anomalies in the historical data.

4.2.3 KU All-Electric School Forecast

The KU All-Electric School forecast includes all customers on the AES rate schedule. Sales to these customers are modeled as a function of the number of KU households, weather, and binary variables to account for anomalies in the historical data.

4.2.4 LG&E Secondary Forecast

The LG&E Secondary forecast includes all customers who receive secondary service on the PS rate schedule and all customers on the TODS rate schedule. Sales to these customers are modeled as a function of weather, specific economic drivers, the number of customers, and other binary variables to account for anomalies in the historical data.

4.2.5 LG&E Special Contract Forecast

LG&E has one customer that is served under a special contract. This customer's consumption is forecasted separately based on information obtained through direct discussions with the customer.

4.2.6 ODP Secondary Forecast

The ODP Secondary forecast includes all customers who receive secondary service on the PS rate schedule and all customers on the TODS rate schedule. Sales to these customers are modeled as a function of weather, the number of customers, and other binary variables to account for anomalies in the historical data.

4.2.7 ODP Municipal Pumping Forecast

The ODP municipal pumping forecast consists of customers on the Water Pumping Service rate schedule. Sales to these customers are modeled using a trend based on recent sales.

4.2.8 KU Primary Forecast

The KU Primary forecast includes all customers who receive primary service on the PS rate schedule and all customers on the TODP rate schedule. Sales to these customers are modeled as a function of an industry-weighted Industrial Production Index and weather. If necessary, the forecast is adjusted to reflect significant expansions or reductions for large customers in these rate classes that are forecast individually based on information obtained through direct discussions with these customers.

4.2.9 KU Retail Transmission Service Forecast

The KU Retail Transmission Service forecast includes customers who receive service on the RTS rate schedule. Sales for a number of large KU RTS customers are forecast individually based on information obtained through direct discussions with these customers. The majority of the remaining RTS customers are mining customers. Sales to these customers are modeled as a function of a mining index.

4.2.10 KU Fluctuating Load Service Forecast

The KU Fluctuating Load Service forecast includes the one customer on the FLS rate schedule and is developed based on information obtained through direct discussions with this customer.

4.2.11 LG&E Primary Forecast

The LG&E Primary forecast includes all customers who receive primary service on the PS rate schedule and all customers on the TODP rate schedule. Sales to these customers are modeled as a function of an industry-weighted Industrial Production Index and weather. If necessary, the forecast is adjusted to reflect significant expansions or reductions for large customers on these rate schedules that are forecast individually based on information obtained through direct discussions with these customers.

4.2.12 LG&E Retail Transmission Service Forecast

The LG&E Retail Transmission Service forecast includes customers who receive service on the RTS rate schedule. Sales for a number of large LG&E RTS customers are forecast individually based on information obtained through direct discussions with these customers. Sales to the remaining customers are modeled using a trend based on recent sales.

4.2.13 ODP Industrial Forecast

The ODP industrial forecast includes all customers receiving primary service on the PS rate schedule as well as customers receiving service on the TODP or RTS rate schedules. ODP industrial sales are modeled as a function of mining production indices and weather.

4.3 KU Municipal Forecasts

KU's municipal customers develop their own sales forecasts. These forecasts are reviewed by KU for consistency and compared to historical sales trends. Any questions or concerns regarding the forecasts are directed to the municipal customers and any forecast revisions resulting from this process are made by the municipal customers.

4.4 Lighting Forecasts

The Lighting forecast includes customers receiving service on the following rate schedules:

- LG&E
  - Lighting Energy Service ("LES")
  - Outdoor Sports Lighting Service ("OSL")
  - Traffic Energy Service ("TES")
  - Unmetered Street Lighting ("UM")
- KU
  - LES
  - OSL
  - TES
  - UM
- ODP
  - UM

All Lighting-related energy is modeled using a trend based on recent sales.

4.5 Distributed Solar Generation Forecast

The distributed solar generation forecast comprises both a consumer choice model and a forecast for the Companies' service territories produced by NREL. The consumer choice model is driven by the levelized cost of energy ("LCOE") for solar installations and retail price of electricity from the grid. Over the forecast timeframe, the consumer choice model and NREL forecast are blended such that by 2050 the forecast is the NREL forecast. The modeling is at the combined Companies' level and capacities are allocated out to various rate schedules (primarily RS, GS, and PS).

4.6 Electric Vehicle Forecast

The electric vehicle forecast comprises both a consumer choice model and a forecast adapted to the Companies' service territories from BNEF. The consumer choice model is driven by the declines in the price of electric vehicles due to projected declines in battery pack costs as well as the cost of internal combustion engine vehicles. The consumer choice model forecast is the near-term forecast and is blended with the BNEF model over the forecast period such that by 2050 the

BNEF model is the forecast. Certain efficiency and miles driven assumptions are used to translate the vehicles-in-operation into an energy impact and that impact is allocated entirely to the Residential class.

4.7 Billed Demand Forecasts

Billed demand forecasts are developed for rate schedules with demand rates based on historical demand factors, where the demand factor is the ratio of the billed demand volume to the billed sales volume. The historical demand factors are multiplied by the forecast of monthly sales to compute forecasted billing demands.

4.8 Weather-Year Forecasts

The Companies develop their hourly energy requirements forecast with the assumption that weather will be average or "normal" in every year (see discussion below in Section 5.2). While this is a reasonable assumption for long-term resource planning, weather from one year to the next is never the same. For this reason, to support the Companies' Reserve Margin Analysis, the Companies produced 45 hourly energy requirement forecasts for 2021 based on weather in each of the last 45 years.

To create these "weather year" forecasts, the Companies develop a model to forecast daily energy requirements as a function of temperature and calendar variables such as day of week and holidays. This model is used to forecast daily energy requirements in each year of the forecast period based on weather from the prior 45 calendar years and calendar variables from the forecast period. Forecasted daily energy requirements are allocated to hours using daily load shapes derived from recent energy requirement profiles for days with similar weather. Finally, to ensure consistency with the Companies' energy forecast, the weather year forecasts are adjusted so that the mean of monthly energy requirements from the weather year forecasts equals monthly energy requirements in the base energy forecast.[9]

5. Data Processing

Most customers' monthly bills include energy that was consumed in portions of more than one calendar month. As a result, the majority of the Companies' forecast models are initially specified to forecast monthly "billed" sales. The following processes are completed to prepare the forecasts for use as inputs to the Companies' revenue and generation forecasts:

1. Billed-to-Calendar Energy Conversion
2. Hourly Energy Requirements Forecast

5.1 Billed-to-Calendar Energy Conversion

The following process is used to allocate sales volumes from billed forecasts to calendar months by rate and revenue class so that the allocated volumes can be used as inputs to the Companies' revenue forecast. Municipal customers and customers on the following rate schedules are billed

[9] The process for computing monthly energy requirements in the base forecast is discussed in Section 5.2.

on a calendar-month basis and are not included in this process: LG&E Special Contract and FLS.

1. Allocate billed forecast volumes for each service territory to calendar months to reflect energy consumption under normal weather conditions.
2. Allocate calendar-month forecast volumes for each service territory to rate schedule and revenue class. In a given month, each rate schedule's share of calendar-month sales is assumed to equal its share of total forecasted billed sales for the month. The allocation of volumes for each rate schedule to revenue class is based historical allocations. All forecast volumes are allocated to one of the following revenue classes: Residential, Commercial, Industrial, Public Authority, Wholesale, and Lighting.

5.2 Hourly Energy Requirements Forecast

The Generation Planning department uses the hourly energy requirements forecast to develop resource expansion plans and a forecast of generation production costs. An hourly energy requirements forecast is developed for each company by adding losses to calendar-month sales and allocating the sum to hours. The result reflects customers' hourly energy requirements under normal weather conditions. The following process is used to develop this forecast:

1. Sum calendar-month forecast volumes by company and add transmission and distribution losses to compute monthly energy requirements. The sum of calendar-month forecast volumes for KU includes forecast volumes for the KU and ODP service territories.
2. Develop normalized load duration curves for each company and month based on 10 years of historical hourly energy requirements. For KU, to model the impact of the municipal departure, this process is completed based on total-company energy requirements as well as energy requirements where the impact of the departing municipals has been removed.
    a. Compute the ratio of hourly energy requirements and monthly energy requirements for each hour and company. Rank the ratios in each month from highest to lowest.
    b. In all months except January and August, the normalized load duration curve is computed by averaging the ratios by month, rank, and company. Because the winter and summer peak can occur in multiple months and the average peak for a season is higher than the average peak for any individual month in the season, the normalized load duration curves for January and August are computed based on the Januaries and Augusts in the historical period with lower-than-average load factors.[10] This process produces seasonal peak demand forecasts for January and August.
3. Allocate monthly energy requirements to hours using the normalized load duration curves. For KU, the normalized load duration curves used to produce hourly energy requirements through April 2019 are based on total-company energy requirements over the past 10 years. Beyond April 2019, the normalized load durations curves reflect the municipal departure.

[10] Specifically, of the ten Januaries and Augusts in the historical period, the analysis uses the months with the 2nd, 3rd, 4th, and 5th lowest load factors.

4. Assign hourly energy requirements to specific hours in each month based on the ordering of days and weekends in the month.
5. Adjust the hourly energy requirements forecast to reflect the forecasted impact of distributed solar generation and electric vehicle load.

6. Review

The final part of the forecast process includes validating and documenting the forecast results. To ensure results are reasonable, the new forecast is compared to (i) the previous forecast and (ii) weather-normalized actual sales for the comparable period in prior years. This process ensures that the forecast is consistent with recent trends in the way customers are using electricity.

Appendix A: Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. Econometric models are well suited to identifying historical trends and to projecting these trends into the future. In contrast, end-use models are able to identify and isolate the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly incorporating trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes this approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The main source of the SAE spreadsheets is the 2017 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \tag{1}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\mathrm{USE}_{m} = a + b_1 \times \mathrm{XHeat}_{m} + b_2 \times \mathrm{XCool}_{m} + b_3 \times \mathrm{XOther}_{m} + \varepsilon_{m} \tag{2}$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier:

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \tag{3}$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} / Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} / Eff_{09}^{Type} \right)} \qquad (4)$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2009 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{09} \times SurfaceArea_{09}} \qquad (5)$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \qquad (6)$$

In Equation 4, 2009 is used as a base year for normalizing the index. As a result, the ratio on the right is equal to 1.0 in 2009. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2009 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{09}^{Type}}{HH_{09}} \times HeatShare_{09}^{Type} \tag{7}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *HeatIndex* value in 2009 will be equal to estimated annual heating intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 1.

Table 1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	760
Electric Space Heating Heat Pump	126

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Price Impacts. In the 2007 version of the SAE models and thereafter, the Heat Index has been extended to account for the long-run impact of electric and natural gas prices. Since the Heat Index represents changes in the stock of space heating equipment, the price impacts are modeled to play themselves out over a 10-year horizon. To introduce price effects, the Heat Index as defined by

Equation 4 above is multiplied by a 10-year moving-average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} / Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} / Eff_{09}^{Type} \right)} \times \left(TenYearMovingAverageElectricPrice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGasPrice_{y,m}\right)^{\gamma} \tag{8}$$

Since the trends in the Structural index (the equipment saturations and efficiency levels) are provided exogenously by the EIA, the price impacts are introduced in a multiplicative form. As a result, the long-run change in the Heat Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels relative to what was contained in the base EIA long-term forecast.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{WgtHDD_{y,m}}{HDD_{09}}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.20} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{09,7}}\right)^{\lambda} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{09,7}}\right)^{\kappa} \tag{9}$$

Where:

- *WgtHDD* is the weighted number of heating degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
- *HDD* is the annual heating degree days for 2009
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)
- *GasPrice* is the average real price of natural gas in month (*m*) and year (*y*)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2009). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \tag{10}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \Big/ Eff_{09}^{Type} \right)} \tag{11}$$

Data values in 2009 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2009. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2009 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{09}^{Type}}{HH_{09}} \times CoolShare_{09}^{Type} \tag{12}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *CoolIndex* value in 2009 will be equal to estimated annual cooling intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 2.

Table 2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,209
Space Cooling Heat Pump	238
Room Air Conditioning	175

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C unit efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Price Impacts. In the 2007 SAE models and thereafter, the Cool Index has been extended to account for changes in electric and natural gas prices. Since the Cool Index represents changes in the stock of space heating equipment, it is anticipated that the impact of prices will be long-term in nature. The Cool Index as defined Equation 11 above is then multiplied by a 10-year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities.

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \big/ Eff_{09}^{Type} \right)} \times \left(TenYearMovingAverageElectric\,Price_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGas\,Price_{y,m}\right)^{\gamma} \quad (13)$$

Since the trends in the Structural index, equipment saturations and efficiency levels are provided exogenously by the EIA, price impacts are introduced in a multiplicative form. The long-run change in the Cool Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels. Without a detailed end-use model, it is not possible to isolate the price impact on any one of these concepts.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{WgtCDD_{y,m}}{CDD_{09}}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.20} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{09}}\right)^{\lambda} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{09}}\right)^{\kappa} \quad (14)$$

Where:

- *WgtCDD* is the weighted number of cooling degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2009.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2009). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \tag{15}$$

The first term on the right-hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{09}^{Type} \Big/ \frac{1}{UEC_{09}^{Type}} \right)} \times MoMult_m^{Type} \times \tag{16}$$
$$(TenYearMovingAverageElectric\,Price)^{\lambda} \times (TenYearMovingAverageGas\,Price)^{\kappa}$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.44}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.46} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.10} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{09}}\right)^{\phi} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{09}}\right)^{\lambda} \quad (17)$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_k ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \quad (18)$$

Supporting Spreadsheets and MetrixND Project Files

The SAE approach described above has been implemented for each of the nine Census Divisions. A mapping of states to Census Divisions is presented in Figure 15. This section describes the contents of each file and a procedure for customizing the files for specific utility data. A total of 18 files are provided. These files are listed in Table 3.

Figure 15: Mapping of States to Census Divisions

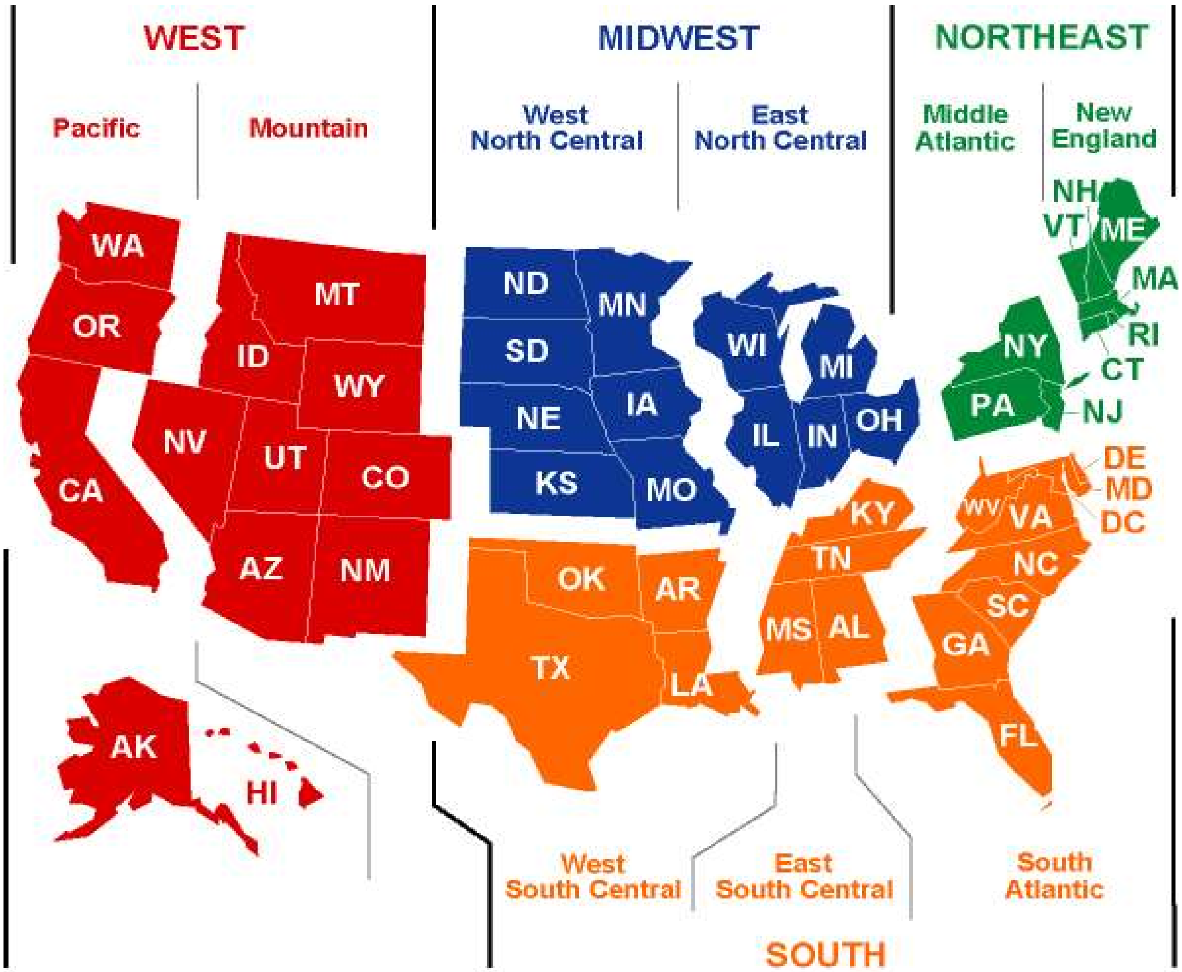


Table 3: List of SAE Files

Spreadsheet	*MetrixND* Project File
NewEngland.xls	SAE_NewEngland.ndm
MiddleAtlantic.xls	SAE_MiddleAtlantic.ndm
EastNorthCentral.xls	SAE_EastNorthCentral.ndm
WestNorthCentral.xls	SAE_WestNorthCentral.ndm
SouthAtlantic.xls	SAE_SouthAltantic.ndm
EastSouthCentral.xls	SAE_EastSouthCentral.ndm
WestSouthCentral.xls	SAE_WestSouthCentral.ndm
Mountain.xls	SAE_Mountain.ndm
Pacific.xls	SAE_Pacific.ndm

As defaults, the SAE spreadsheets include regional data, but utility data can be entered to generate the *Heat*, *Cool*, and *Other* equipment indices used in the SAE approach. The *MetrixND* project files link to the data in these spreadsheets. These project files calcualte the end-use *Usage* variables are constructed and the estimated SAE models.

Each of the nine SAE spreadsheets contains the following tabs:

- **Definitions -** Contains equipment, end use, worksheet, and Census Division definitions.
- **Intensities -** Calculates the annual equipment indices.
- **Shares -** Contains historical and forecasted equipment shares. The default forecasted values are provided by the EIA. The raw EIA projections are provided on the *EIAData* tab.
- **Efficiencies -** Contains historical and forecasted equipment efficiency trends. The forecasted values are based on projections provided by the EIA. The raw EIA projections are provided on the *EIAData* tab.
- **StructuralVars -** Contains historical and forecasted square footage, number of households, building shell efficiency index, and calculation of structural variable. The forecasted values are based on projections provided by the EIA.
- **Calibration -** This tab contains calculations of the base year *Intensity* values used to weight the equipment indices.
- **EIAData -** Contains the raw forecasted data provided by the EIA.
- **MonthlyMults -** Contains monthly multipliers that are used to spread the annual equipment indices across the months.
- **EV -** Worksheet for incorporating electric vehicle (EV) impacts.
- **PV -** Worksheet for incorporating photovoltaic battery (PV) impacts.

The *MetrixND* Project files are linked to the *AnnualIndices*, *ShareUEC*, and *MonthlyMults* tabs in the spreadsheets. Sales, economic, price and weather information for the Census Division is provided in the linkless data table *UtilityData*. In this way, utility specific data and the equipment indices are brought into the project file. The *MetrixND* project files contain the objects described below.

Parameter Tables

- **Elas.** This parameter table includes the values of the elasticities used to calculate the *Usage* variables for each end-use. There are five types of elasticities included on this table.

  - Economic variable elasticities
  - Short-term own price elasticities
  - Short-term cross price elasticities
  - Long-term own price elasticities

- Long-term cross price elasticities

The short-term price elasticities drive the end-use usage equations. The long-term price elasticities drive the Heat, Cool and other appliance indices. The combined price impact is an aggregation of the short and long-term price elasticities. As such, the long-term price elasticities are input as incremental price impact. That is, the long-term price elasticity is the difference between the overall price impact and the short-term price elasticity.

Data Tables

- **AnnualEquipmentIndices** links to the *AnnualIndices* tab for heating and cooling indices, and *ShareUEC* tab for water heating, lighting, and appliances in the SAE spreadsheet.
- **UtilityData** is a linkless data table that contains sales, price, economic and weather data specific to a given Census Division.
- **MonthlyMults** links to the corresponding tab in the SAE spreadsheet.

Transformation Tables

- **EconTrans** computes the average usage, and household size, household income, and price indices used in the usage equations.
- **WeatherTrans** computes the HDD and CDD indices used in the usage equations.
- **ResidentialVars** computes the *Heat*, *Cool* and *Other Usage* variables, as well as the *XHeat*, *XCool* and *XOther* variables that are used in the regression model.
- **BinaryVars** computes the calendar binary variables that could be required in the regression model.
- **AnnualFcst** computes the annual historical and forecast sales and annual change in sales.
- **EndUseFcst** computes the monthly sales forecasts by end uses.

Models

- **ResModel** is the Statistically Adjusted End-Use Model.

Steps to Customize the Files for Your Service Territory

The files that are distributed along with this document contain regional data. If you have more accurate data for your service territory, you are encouraged to tailor the spreadsheets with that information. This section describes the steps needed to customize the files.

Minimum Customization

- Save the *MetrixND* project file and the spreadsheet into the same folder
- Select the spreadsheet and *MetrixND* project file from the appropriate Census Division

- Open the spreadsheet and navigate to the *Calibration* tab
- In cell "B9", replace base year Census Division use-per-customer with observed use-per-customer for your service territory
- Save the spreadsheet and open the *MetrixND* project file
- Click on the *Update All Links* button on the *Menu* bar
- Review the model results

Further Customization of Starting Usage Levels

In addition to the minimum steps listed above, you can also utilize model-based calibration process described above on pages 15-16 to further fine-tune starting year usage estimates to your service territory.

Customizing the End-use Share Paths

You can also install your own share history and forecasts. To do this, navigate to the *Share* tab in the spreadsheet and paste in the values for your region. Make sure that base year shares on the *Calibration* tab reflect changes on the *Shares* tab.

Customizing the End-use Efficiency Paths

Finally, you can override the end-use efficiency paths that are contained on the *Efficiencies* tab of the spreadsheet.

Appendix B: Commercial Statistically Adjusted End-Use Model

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, econometric models are well suited to identifying historical trends and to projecting these trends into the future. In contrast, end-use models are able to incorporate the end-use factors driving energy use. By including end-use structure in an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to the SAE approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast, thereby providing a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and efficiency levels, SAE models can explain changes in usage levels and weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2017 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

1.1 Commercial Statistically Adjusted End-Use Model Framework

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + \text{Other}_{y,m} \quad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \tag{2}$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end-uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating intensity,
- Commercial output and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m} \tag{3}$$

Where

- $XHeat_{y,m}$ is estimated heating energy use in year y and month m,
- $HeatIndex_y$ is the annual index of heating equipment, and
- $HeatUse_{y,m}$ is the monthly usage multiplier.

The heating equipment index is composed of electric space heating intensity. The index will change over time with changes in heating intensity. Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{13} \times \frac{(HeatIntensity_y)}{(HeatIntensity_{13})} \tag{4}$$

In this expression, 2013 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2013. In other years, it will be greater than 1.0 if intensity levels are above their 2004 level.

$$HeatSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Heating} \times \left(\frac{CommercialSales_{13}}{\sum_{e} {kWh}/{Sqft_e}}\right) \tag{5}$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2013 will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, and prices. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{WgtHDD_{y,m}}{HDD_{13}}\right) \times \left(\frac{Output_y}{Output_{13}}\right) \times \left(\frac{Price_{y,m}}{Price_{13}}\right)^{-0.18} \tag{6}$$

Where

- *WgtHDD* is the weighted number of heating degree days in year *y* and month *m*. This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month
- *HDD* is the annual heating degree days for 2013,
- *Output* is a real commercial output driver in year *y*,
- *Price* is the average real price of electricity in month *m* and year *y*,

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2013). The first terms, which involve heating degree days, serves to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling intensity,
- Commercial output and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \tag{7}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year *y* and month *m*,
- $CoolIndex_y$ is an index of cooling equipment, and
- $CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_y = CoolSales_{13} \times \frac{\left(CoolShare_y / Eff_y \right)}{\left(CoolShare_{13} / Eff_{13} \right)} \tag{8}$$

Data values in 2013 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2013. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2013 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{13} = \left(\frac{kWh}{Sqft} \right)_{Cooling} \times \left(\frac{CommercialSales_{13}}{\sum_e kWh / Sqft_e} \right) \tag{9}$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in 2013 will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{WgtCDD_{y,m}}{CDD_{13}}\right) \times \left(\frac{Output_{y}}{Output_{13}}\right) \times \left(\frac{Price_{y,m}}{Price_{13}}\right)^{-0.18} \tag{10}$$

Where

- *WgtCDD* is the weighted number of cooling degree days in year *y* and month *m*. This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2013.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2013). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in commercial output and prices.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment intensities,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

The second term on the right hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{13}^{Type} \times \left(\frac{Share_y^{Type} \big/ Eff_y^{Type}}{Share_{13}^{Type} \big/ Eff_{13}^{Type}} \right) \tag{12}$$

Where

- *Weight* is the weight for each equipment type,
- *Share* represents the fraction of floor stock with an equipment type, and
- *Eff* is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{13}^{Type} = \left(\frac{kWh}{Sqft} \right)_{Type} \times \left(\frac{CommercialSales_{13}}{\sum_e kWh \big/ Sqft_e} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end-uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.44}\right) \times \left(\frac{Output_y}{Output_{13}}\right) \times \left(\frac{Price_{y.m}}{Price_{13}}\right)^{-0.18} \tag{14}$$

In this expression, the elasticities on output and real price are computed from the COMMEND default values.

1.2 Supporting Spreadsheets and *MetrixND* Project Files

The SAE approach described above has been implemented for each of the nine census divisions. This section describes the contents of each file and a procedure for customizing the files for specific utility data. A total of 18 files are provided. These files are listed in Table 1.

Table 1: List of SAE Files

Spreadsheets	*MetrixND* Project Files
NewEnglandCom17.xls	NewEnglandCom17.ndm
MiddleAtlanticCom17.xls	MiddleAtlanticCom17.ndm
EastNorthCentralCom17.xls	EastNorthCentralCom17.ndm
WestNorthCentralCom17.xls	WestNorthCentralCom17.ndm
SouthAtlanticCom17.xls	SouthAltanticCom17.ndm
EastSouthCentralCom17.xls	EastSouthCentralCom17.ndm
WestSouthCentralCom17.xls	WestSouthCentralCom17.ndm
MountainCom17.xls	MountainCom17.ndm
PacificCom17.xls	PacificCom17.ndm

As defaults, the SAE spreadsheets include regional data, but utility data can be entered to generate the *Heat*, *Cool*, and *Other* equipment indices used in the SAE approach. The data from these spreadsheets are linked to the *MetrixND* project files. In these project files, the end-use *Usage* variables (Equations 6, 10, and 14 above) are constructed and the SAE model is estimated.

The nine spreadsheets contain the following tabs.

- **EIAData** contains the raw forecasted data provided by the EIA
- **BaseYrInput** contains base year Census Division intensities by end-use and building type as well as default building type weights. It also contains functionality for changing the weights to reflect utility service territory.
- **Efficiency** contains historical and forecasted end-use equipment efficiency trends. The forecasted values are based on projections provided by the EIA.
- **Shares.** This tab contains historical and forecasted end-use saturations.
- **Intensity** contains the annual intensity (kWh/sqft) projections by end-use.
- **AnnualIndices** contains the annual *Heat*, *Cool* and *Other* equipment indices.
- **FloorSpace** contains the annual floor space (sqft) projections by end-use.
- **PV** incorporates the impact of photovoltaic batteries into the forecast.
- **Graphs** contains graphs of Efficiency and Intensities, which can be updating by selecting from the list in cell B2.

The *MetrixND* project files contain the following objects.

Parameter Tables

- **Parameters.** This parameter table includes the values of the annual HDD and CDD in 2013 used to calculate the *Usage* variables for each end-use.
- **Elas.** This parameter table includes the values of the elasticities used to calculate the *Usage* variables for each end-use.

Data Tables

- **AnnualIndices.** This data table is linked to the *AnnualIndices* tab in the Commercial SAE spreadsheet and contains sales-adjusted commercial SAE indices.
- **Intensity.** This data table is linked to the *Intensity* tab in the Commercial SAE spreadsheet.
- **FloorSpace.** This data table links to *FloorSpace* tab in the Commercial SAE spreadsheet.
- **UtilityData.** This linkless data table contains Census Division level data. It can be populated with utility-specific data.

Transformation Tables

- **EconTrans.** This transformation table is used to compute the output and price indices used in the usage equations.
- **WeatherTrans.** This transformation table is used to compute the HDD and CDD indices used in the usage equations.
- **CommercialVars.** This transformation table is used to compute the *Heat*, *Cool* and *Other Usage* variables, as well as the *XHeat*, *XCool* and *XOther* variables that are used in the regression model. Structural variables based on the intensity/floor space combination are also calculated here.
- **BinaryVars.** This transformation table is used to compute the calendar binary variables that could be required in the regression model.
- **AnnualFcst.** This transformation table is used to compute the annual historical and forecast sales and annual change in sales.
- **EndUseFcst.** This transformation table breaks the forecast down into its heating, cooling and other components.

Models

- **ComSAE:** The commercial SAE model (energy forecast driven by end-use indices, price, and output projections).
- **ComStruct:** Simple stock model (energy forecast driven by end-use energy intensities, and square footage).

2019 Business Plan Electric Forecast

Sales Analysis & Forecasting
May 14, 2018

PPL companies

Forecast Summary

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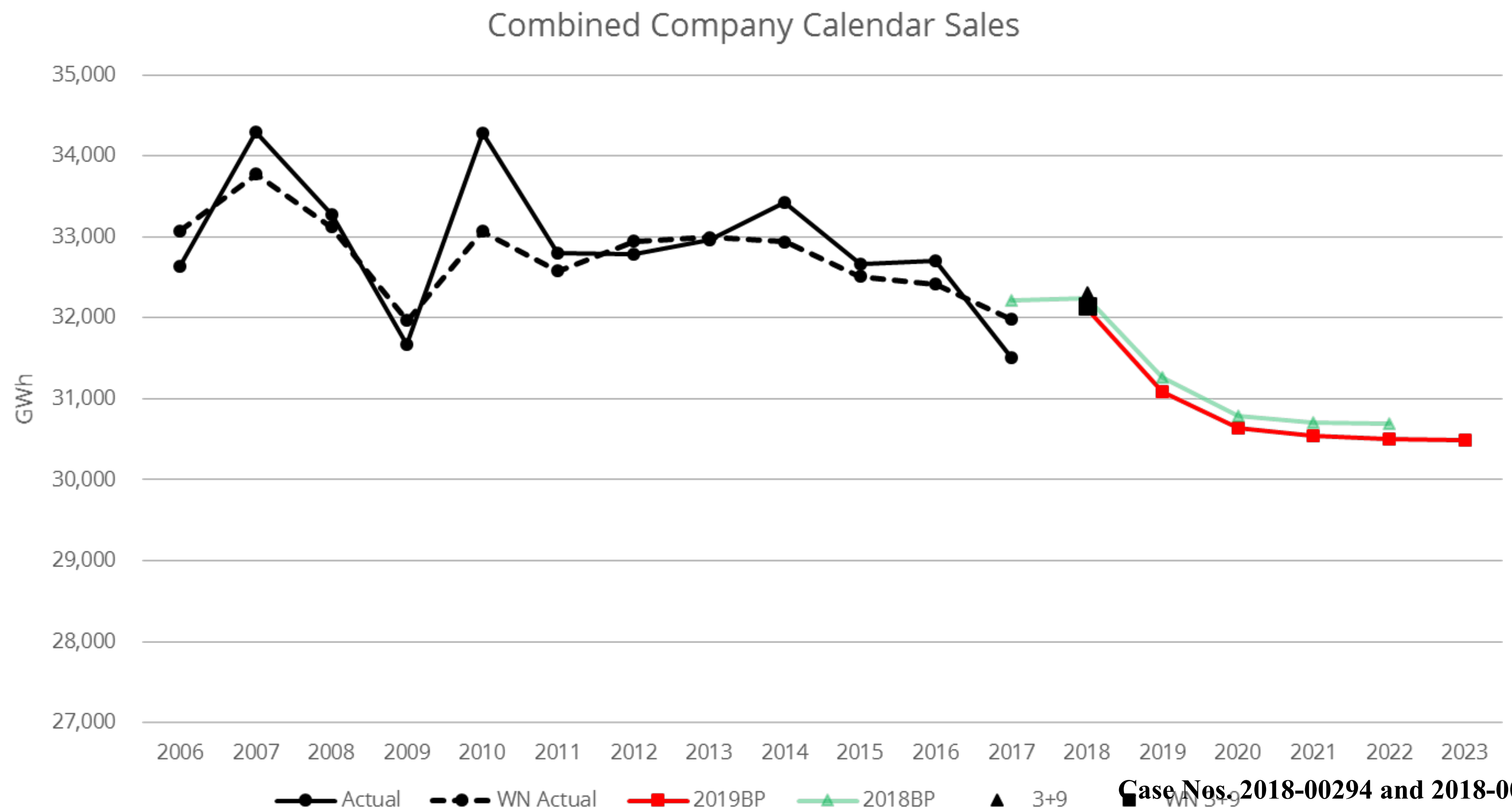
- Sales volumes decreased 0.5% or approximately 160 GWh from the 2018 Plan in 2019
  - 80 GWh decrease due to [redacted] with an additional 30 GWh decrease from other Major Accounts and Industrials
  - Customer growth in Louisville and Lexington remains strong and offsets declining use-per-customer in 2017
- Municipal departure reduces sales approximately 1,000 GWh in 2019
- Electric Vehicles and Distributed Generation have limited impact in short-term
  - Longer-term implications considered as scenarios for the IRP

Key Assumptions

- Economic conditions remain robust with limited impact on sales volumes from economic growth
- Household growth of 0.5% driven by Louisville and Lexington
- Increased LED lighting penetration provides further decreases in use-per-customer
- Distributed solar and electric vehicle penetration continue to increase but no significant sales impact through 2025
- No adjustments for AMS related sales impacts (e.g. customer responses, theft reductions, outage reduction time)
- No assumptions on increased battery storage to manage demand charges

Municipals departing in May 2019 remains the largest change



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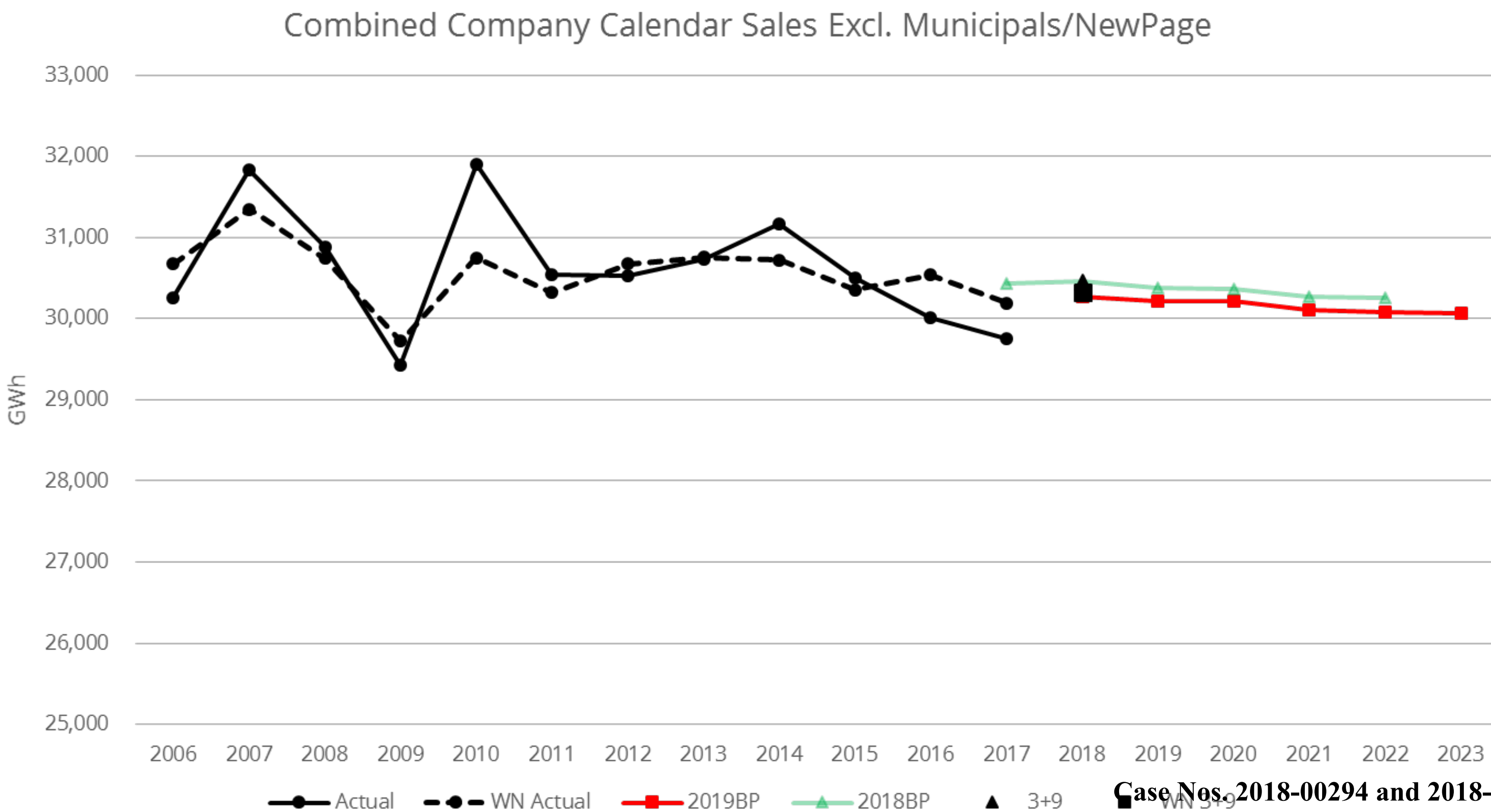
2019 Plan Sales excluding Municipals decline 150 GWh 2019-2023 due to Residential and Commercial



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LG&E KU
PPL companies

[redacted] and other Industrials drive Plan over Plan variance; Residential & Commercial 37 GWh below 2018 BP in 2019

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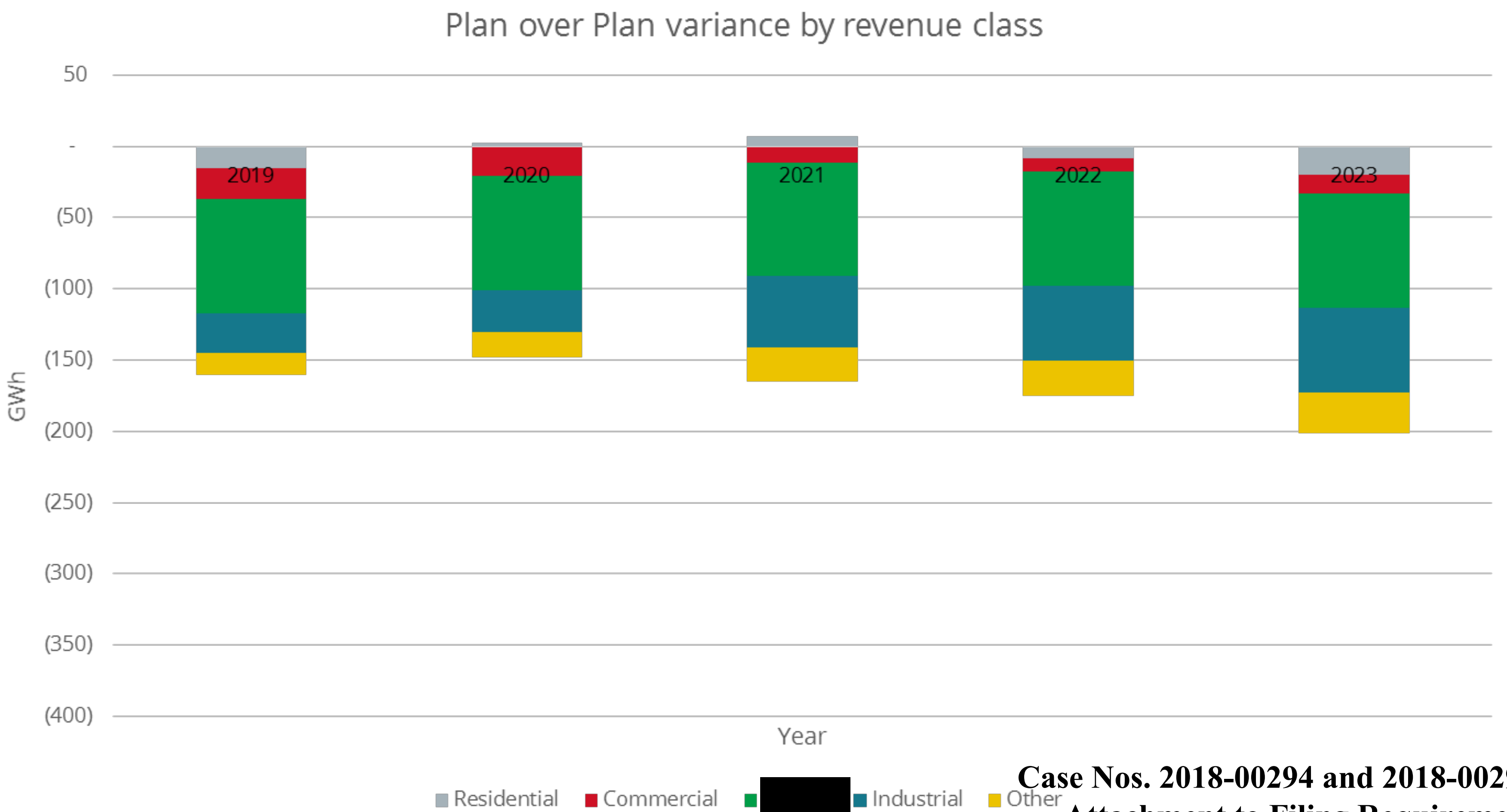

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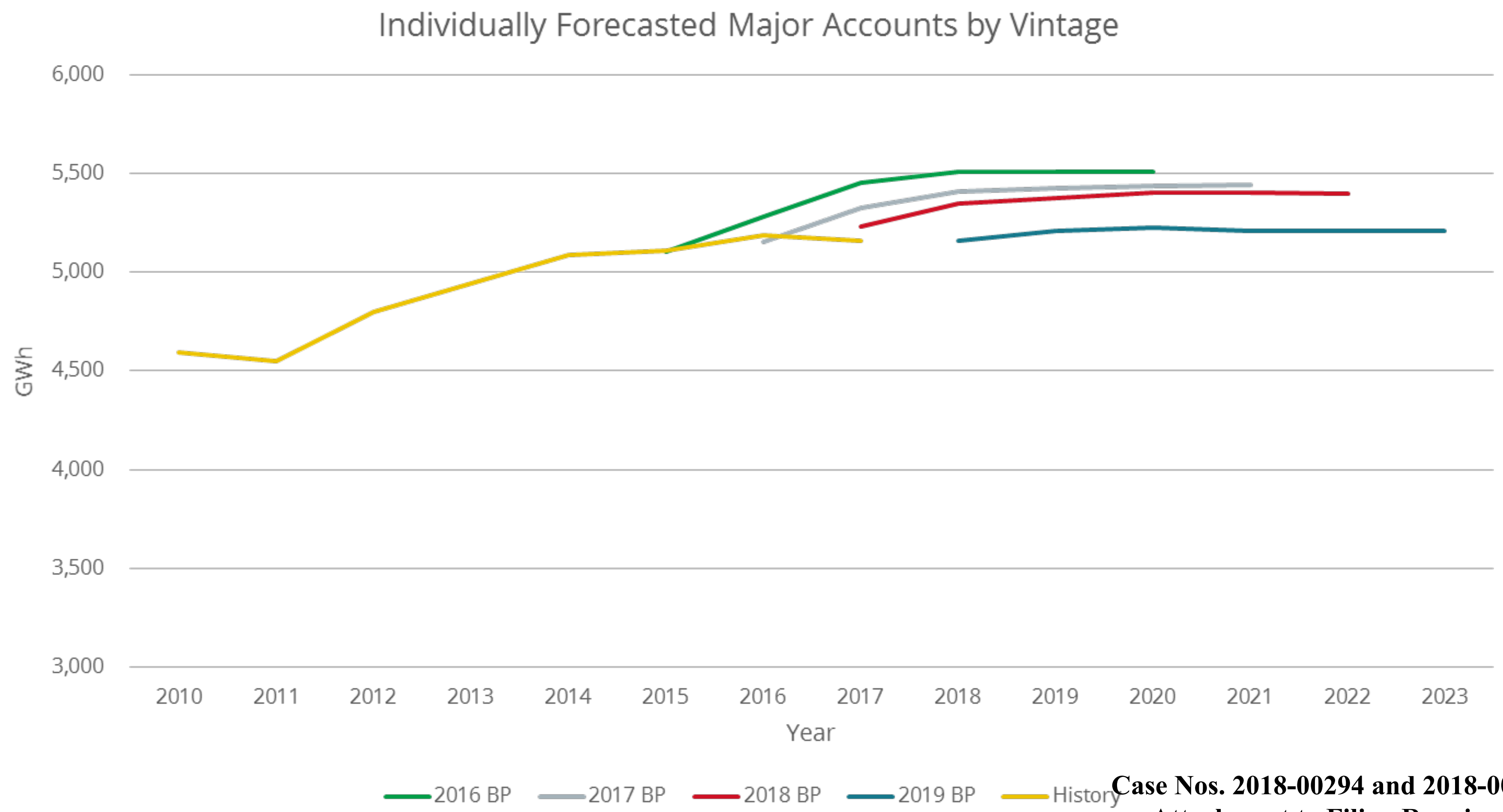
Individually forecasted customers in line with recent history



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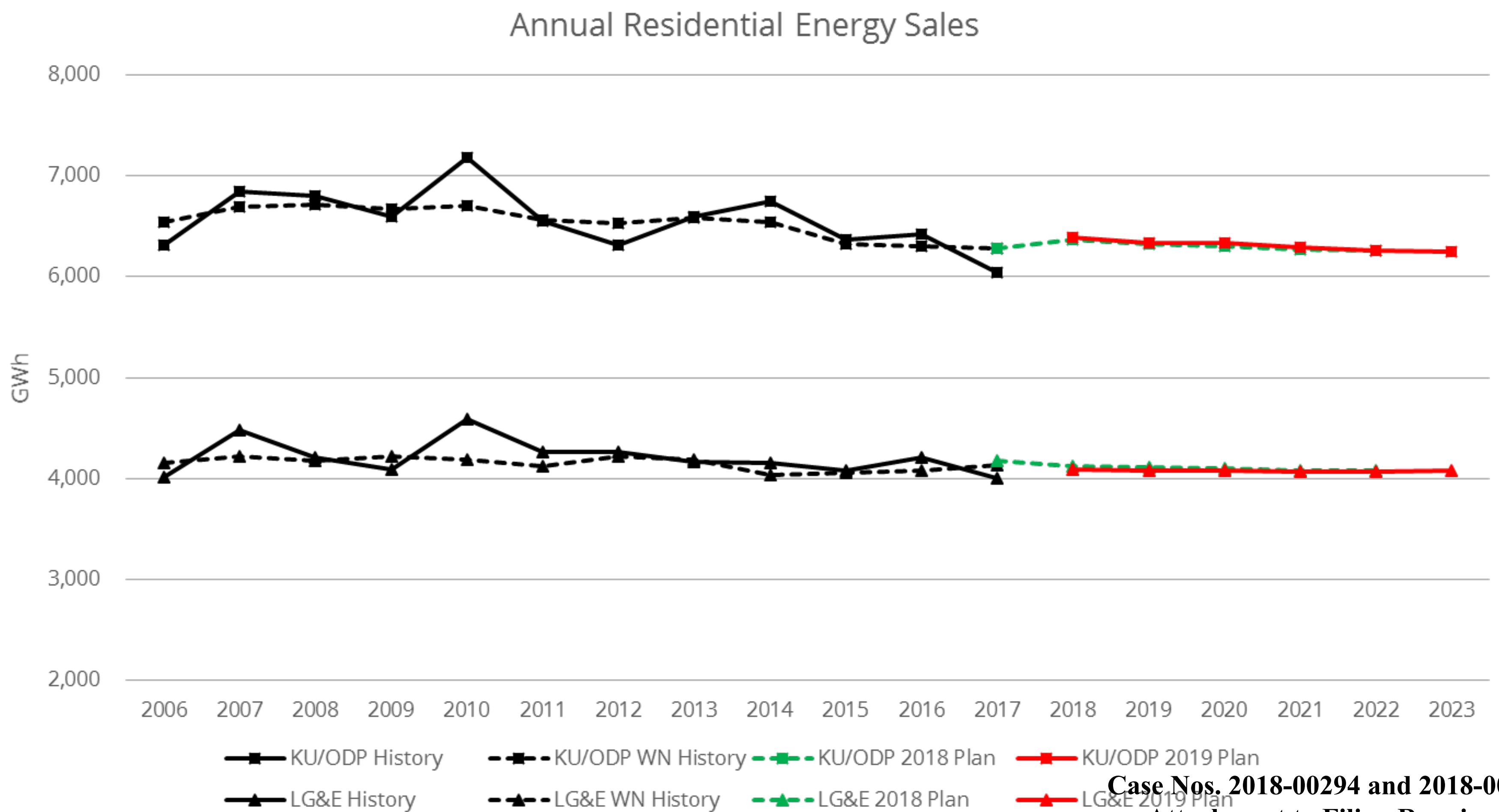
LG&E KU PPL companies

Residential Sales 15 GWh lower than 2018BP in 2019



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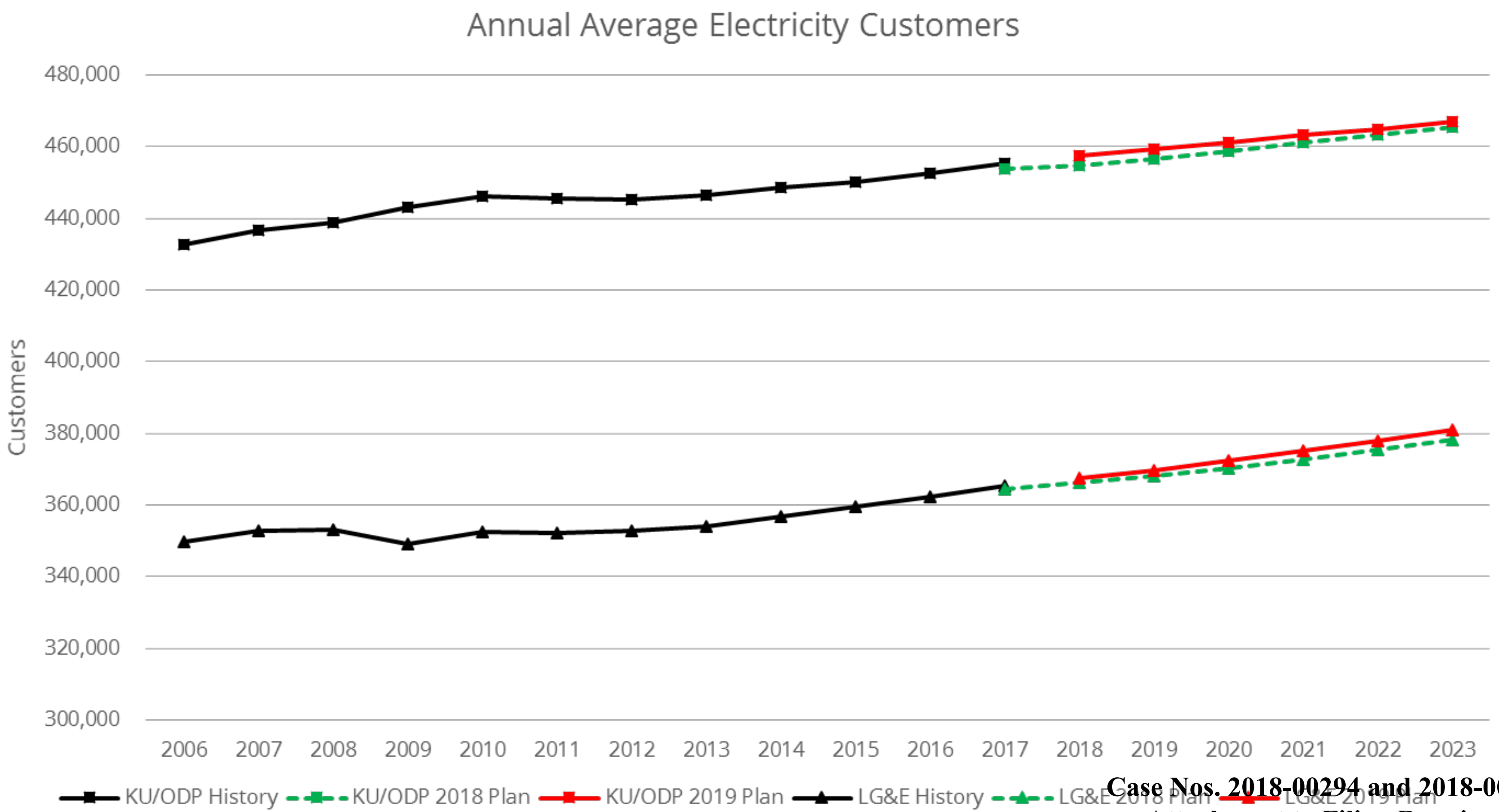
Customer growth in Louisville and Lexington remains strong and above 2018 Plan levels



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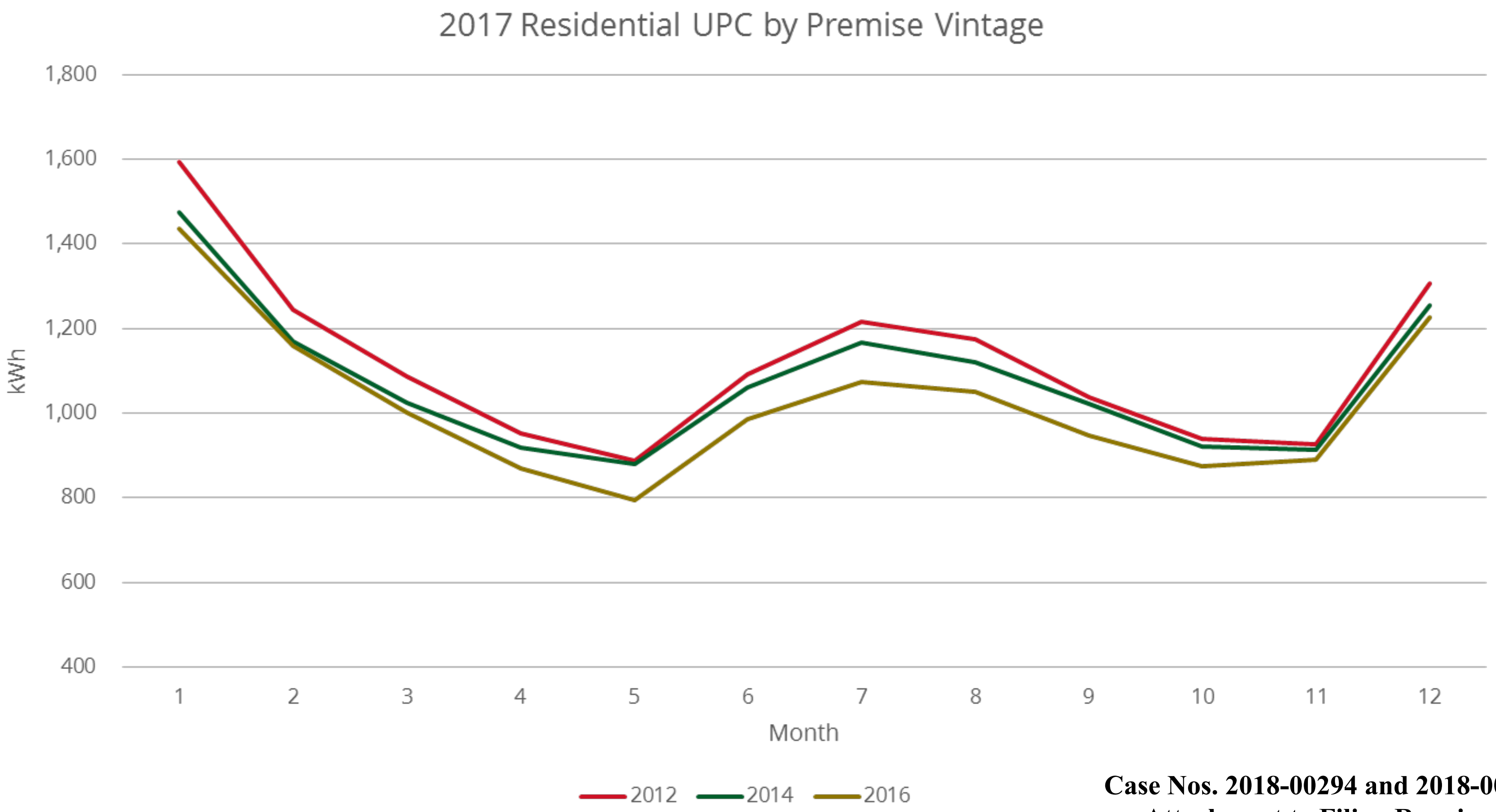
LG&E KU PPL companies

Residential use-per-customer reflects changes in housing, heat source and appliance efficiencies

- New premises have a greater penetration of electric heating than existing stock at both LG&E and KU
- Use-per-customer lower despite increased electric heating due to housing type and appliance efficiencies
- Improved AC efficiency continues to lower summer cooling load
- LED lighting penetration remains below 40% with significant opportunity in replacement of halogen bulbs

Cooling efficiencies and electric heating penetration driving changes in Residential profiles



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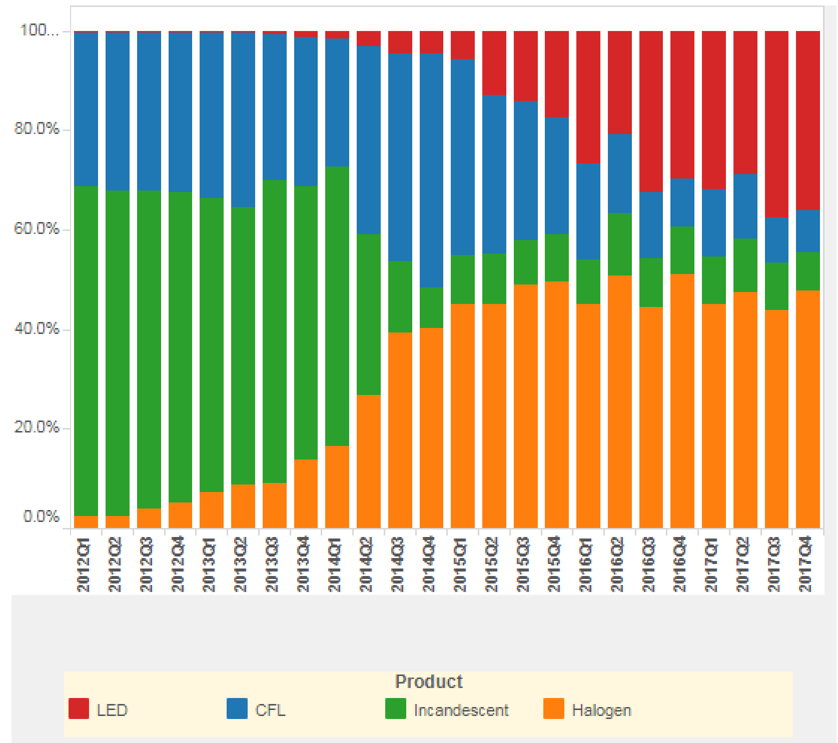
Decreasing use-per-customer despite higher electric heating penetration

	KU			LG&E		
	Electric Heating Penetration	Avg 2017 Billed kWh	Customers	Electric Heating Penetration	Avg 2017 Billed kWh	Customers
2010	53%	13,195	394,837	22%	11,119	334,978
2011	71%	13,418	4,028	35%	11,416	2,444
2012	69%	13,036	3,904	38%	12,704	2,102
2013	69%	12,797	4,014	42%	12,470	2,523
2014	67%	12,908	3,444	46%	11,210	3,258
2015	68%	12,387	3,485	49%	11,138	3,310
2016	68%	11,266	4,144	49%	10,610	3,198

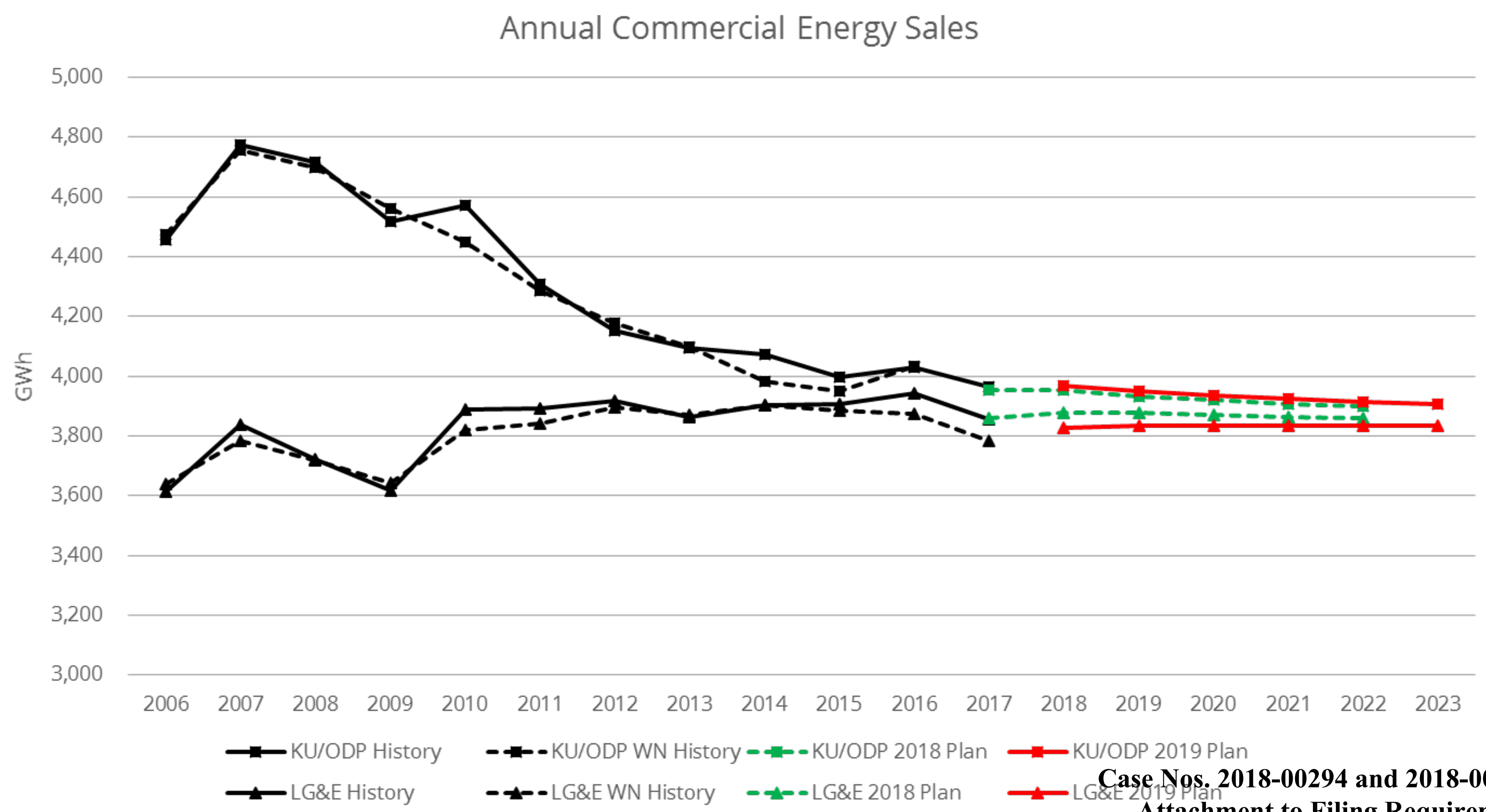
Despite recent sales trends, LEDs remain at a relatively low saturation

- Rapid increase in LED penetration since 2014 from replacement of incandescent and CFL bulbs
- Future LED growth likely in replacing existing halogen lights which remain above 40%



LG&E KU PPL companies

Commercial volumes remain consistent with 2018 Plan



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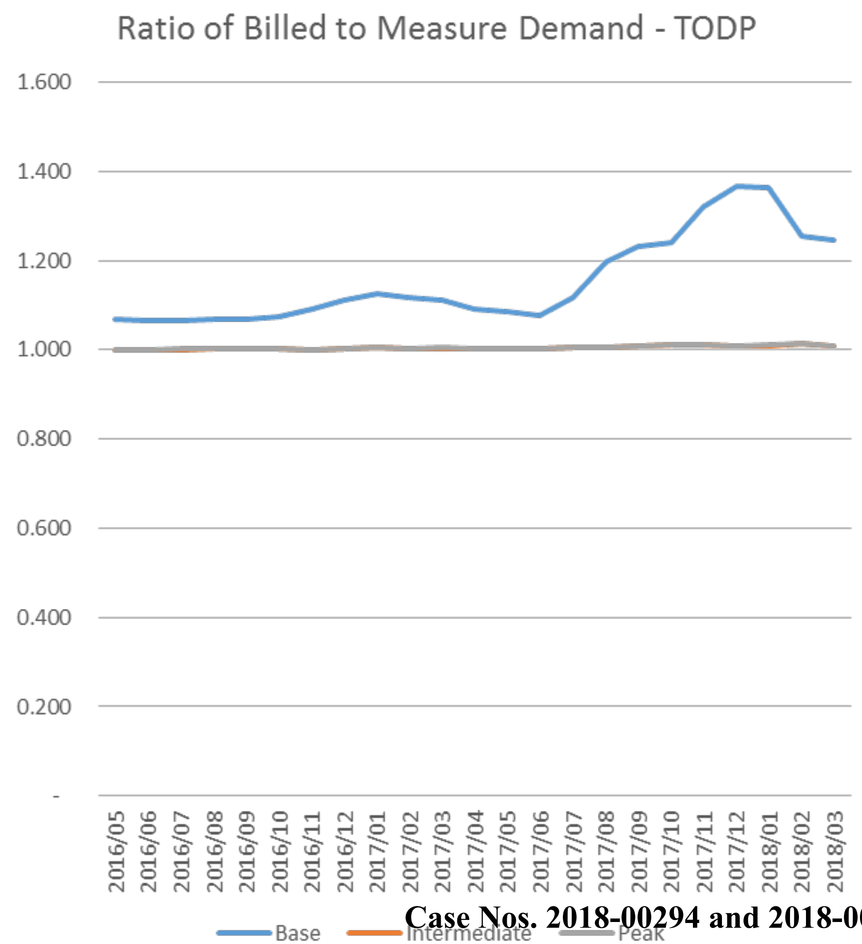
LG&E KU
PPL companies

Distributed Solar and Electric Vehicle penetration remains low until mid-2020s

Year	Solar Installed Capacity (MW)	Non-Utility Solar Generation (MWh)		EVs	EV Electricity Sales (MWh)
2010	0	191		1	3
2015	3	3,275		650	1,851
2020	7	8,479		2,903	8,709
2025	21	24,332		8,341	26,273
2030	96	114,383		22,622	74,651
2035	238	282,131		66,723	230,195
2040	593	701,981		159,769	575,167
2045	1,072	1,258,922		300,711	1,082,560
2050	1,571	1,826,131		491,793	1,770,454

Billing Demands have become an increasingly important component of the forecast process

- Process overview:
  - Load factor methodology to align with sales forecast
  - Historically small differences between billed and measured
- FLS, RTS, TOD-Primary, and TOD-Secondary have 100% ratchets on base demand
- Since August 2017, Demand Revenues accounted for 21% of total revenue (excluding Demand ECR)



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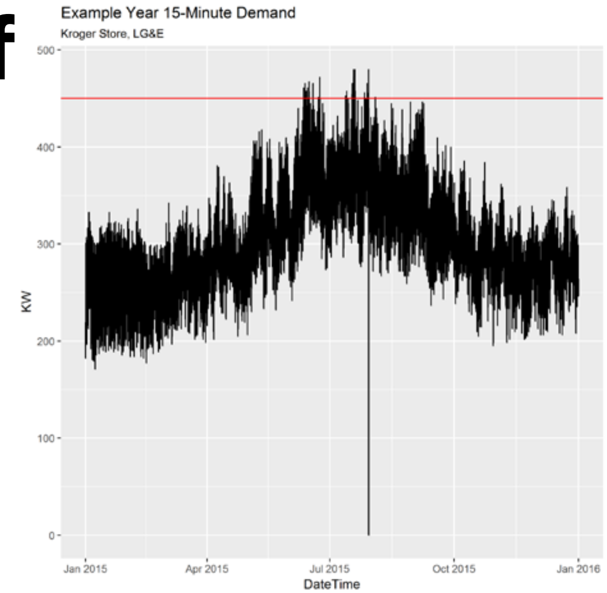
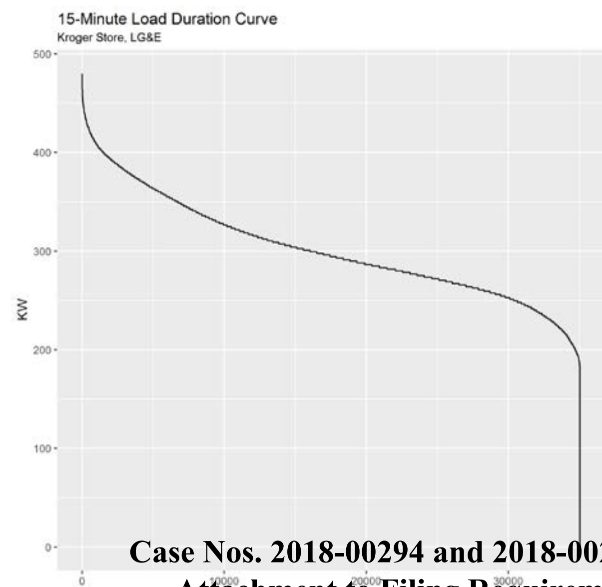
Limited data on the impact of recent price signals

- Increased revenue risk in a small number of hours
- Demand charges of $15/kW have significant revenue vulnerability to behind the meter storage
- Risks
  - Changing relationship between billed and measured demand
  - Customers will consider BTM storage to mitigate demand charges and ratchets





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Conclusion

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- [redacted] and other Industrial volumes account for most changes in sales volumes from 2018 Plan
- Reduced Residential & Commercial use-per-customer offset by robust customer growth
  – Use-per-customer changes from new premise type, heating source & efficiency gains
- Demand Revenues
  – PS demand charge & ratchets both provide strong price signals encouraging behavioral changes and BTM storage

Appendix

Plan over plan Major Account changes in 2019

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Major Account	2019 Plan (GWh)	2018 Plan (GWh)	Delta (GWh)	Notes
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Electric Class Load Profile Forecast Process

PPL companies

Sales Analysis & Forecasting
September 2018

Table of Contents

1. Introduction

The Sales Analysis & Forecasting group develops the class load profile forecasts for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") as inputs to the Companies' cost of service studies. The class load profile forecasts provide an estimate of each class's contribution to forecasted hourly energy requirements. The purpose of this document is to summarize the process used to produce and validate these forecasts.

2. Input Data

Table 1 contains a summary of key inputs to this process. The processes used to forecast monthly sales and hourly energy requirements are summarized in a separate document ("Electric Sales & Demand Forecast Process").

Table 1: Inputs to Class Load Profile Forecast

Data Input	Source
5- and 15-Minute Customer Energy Usage	History: MV90 System
Monthly Sales by Class	History: CCS / Accounting Forecast: Business Plan
Hourly Energy Requirements by Company	History: Energy Management System Forecast: Business Plan
Loss Percentages by Service Level	History: 2012 Line Loss Study

3. Methodology

LG&E and KU develop class load profile forecasts for the classes listed in Table 2. With limited exceptions, each class comprises all or a portion of one rate schedule. For example, the Commercial Power Service Primary class comprises commercial customers who take primary service on the Power Service ("PS") rate schedule. The goal of the forecast process is to develop profiles for each class that reflect the classes' hourly energy requirements under "normal" weather conditions.[1]

[1] "Normal" weather is defined as the average weather over a 20-year historical period.

Table 2: LG&E and KU Classes

Class	Company	Rate Schedule	Sample / Census	Weather-Sensitive
Residential	LG&E, KU	RS, VFD	Sample	Yes
Residential Time-of-Day	LG&E, KU	RTOD	Sample	Yes
Electric Vehicle Charging	LG&E, KU	EVC	Census	No
General Service	LG&E, KU	GS	Sample	Yes
Commercial Power Service Primary	LG&E	PS	Sample	Yes
Commercial Power Service Secondary	LG&E	PS	Sample	Yes
Commercial Time-of-Day Primary	LG&E	TODP	Census	Yes
Commercial Time-of-Day Secondary	LG&E	TODS	Census	Yes
Industrial Power Service Primary	LG&E	PS	Sample	No
Industrial Power Service Secondary	LG&E	PS	Sample	No
Industrial Time-of-Day Primary	LG&E	TODP	Census	No
Industrial Time-of-Day Secondary	LG&E	TODS	Census	No
Louisville Water Company	LG&E	Special Contract	Census	No
All Electric Schools	KU	AES	Sample	Yes
Power Service Secondary	KU	PS	Sample	Yes
Time-of-Day Secondary	KU	TODS	Census	Yes
Power Service Primary	KU	PS	Sample	Yes
Time-of-Day Primary	KU	TODP	Census	Yes
Fluctuating Load Service	KU	FLS	Census	No
Retail Transmission Service	LG&E, KU	RTS	Census	No
Outdoor Sports Lighting	LG&E, KU	OSL	Sample	No
Unmetered Lighting	LG&E, KU	LS, RLS	Sample	No
Lighting Energy Service	LG&E, KU	LE	Sample	No
Traffic Energy Service	LG&E, KU	TE	Sample	No
Company Uses	LG&E, KU	N/A	N/A	Yes
Muni Primary	KU	Special Contract	Census	Yes
Muni Transmission	KU	Special Contract	Census	Yes
Old Dominion Power	KU	N/A	Census	Yes

The Companies' most recent cost of service studies focused on the twelve months ending April 2020 ("Forecasted Test Period"). To forecast class load profiles for this period, the Companies first developed historical class load profiles for the twelve months ending April 2018 ("Historical Period"). Then, these historical load profiles were used along with other forecasted inputs to forecast class load profiles for Forecasted Test Period. This process is completed separately for LG&E and KU. The following sections summarize the process in more detail.

3.1 Historical Period Class Load Profiles

Hourly class load profiles for the Historical Period are developed using customers' 5- and 15-minute energy usage data ("interval data"). The Companies have interval data for all customers in classes with demand rates that vary by time of day. Therefore, historical profiles for these "census" classes are created simply by aggregating interval data for all customers in the class by hour. For each of the classes without interval data for all customers ("sample" classes), historical profiles are created based on interval data for a sample of customers. The samples were designed for this purpose and account for differences within each class in the way customers use electricity.

For all classes, the Companies ensure that the sum of hourly demands in each month equals actual monthly sales according to accounting records. In addition, the Companies ensure that the sum of class demands in each hour plus losses and company uses equals the actual hourly energy requirements according to the Energy Management System ("EMS").

3.2 Forecasted Test Period Class Load Profiles

A key consideration in developing class load profile forecasts is accounting for differences in weather and non-weather factors between the Historical Period and the Forecasted Test Period; non-weather factors include the number of customers, non-heating or cooling end-use efficiencies, and industrial production levels. In the Forecasted Test Period, the monthly sum of hourly loads for each class is aligned with the Companies' forecast of monthly energy requirements. This accounts for monthly differences in weather and non-weather factors, but because the Companies' cost of service studies are focused on hours with a loss-of-load probability, additional steps must be taken to ensure the class profiles on high load days are reasonable.

To develop daily class load profiles, the Companies rank the daily system peaks in the Historical Period and the Forecasted Test Period by month. For each month in the Forecasted Test Period, class profiles on the day with the highest system peak (daily rank = 1) are forecasted based on class profiles from the day in the Historical Period with the highest system peak. Then, class profiles on the day with the second highest system peak (daily rank = 2) are forecasted based on class profiles from the day in the Historical Period with the second highest system peak, and so on.

This ranking process ensures that the highest daily profiles in the Forecasted Test Period are forecasted based on days in the Historical Period with similar weather. Even so, weather differences can still exist between the Historical Period and Forecasted Test Period on days with the same daily rank. For example, weather on the peak day in August 2017 (Historical Period) was milder than a normal summer peak day and weather on the peak day in January 2018 (Historical Period) was colder than a normal winter peak day. To account for these differences, daily class profiles for weather-sensitive and non-weather-sensitive classes are forecasted differently.

Table 2 indicates which classes are considered weather-sensitive and non-weather-sensitive.[2] For each of the non-weather-sensitive classes, monthly class load profiles in the Historical Period are scaled up or down so that the sum of hourly loads in each month equals the Companies' energy requirements forecast for the corresponding month of the Forecasted Test Period. Then, the daily load profile in the Forecasted Test Period is equal to the "scaled" daily load profile from the day in the Historical Period with the same daily rank. The scaling process accounts for non-weather-related differences between the Historical Period and the Forecasted Test Period. With one exception, load factors for non-weather-sensitive classes in each month of the Forecasted Test Period are equal to load factors from the corresponding month in the Historical Period.[3]

For each of the weather-sensitive classes, the daily load profile in the Forecasted Test Period is based on the class's share of weather-sensitive load on the day in the Historical Period with the same daily rank. Weather-sensitive load in a given hour is equal to the system load less the sum of loads from non-weather-sensitive classes. This process accounts for the typically small weather differences between the Historical Period and Forecasted Test Period on days with the same daily rank.[4] A scaling adjustment is also made to weather-sensitive classes to align the sum of forecasted loads by month with the Companies' energy requirements forecast.

Because the Companies' cost of service studies are focused on hours with a loss-of-load probability, the class load forecasting process prioritizes accuracy on high load days. At the end of the process, the sum of class loads in each hour of the Forecasted Test Period equals the forecasted system load for that hour. In addition, the sum of loads for each class and month is closely aligned with the Companies' forecast of monthly class energy requirements.

4. Review

The forecast process has several built-in controls to ensure that the forecasted class load profiles are consistent with the separately-developed forecasts of hourly system energy requirements and monthly class-level sales. At the end of the process, the Companies review the class load profile forecasts to ensure that they are reasonable. Because the Companies' cost of service studies are focused on hours with a loss-of-load probability, this review is focused primarily on high load days to ensure they are reasonable in light of historical days on which the forecasts are based.

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[2] This designation was determined based on the Companies' sales forecasting process. If weather was a significant explanatory variable in specifying a class's forecast model, the class is considered weather-sensitive.
[3] The one exception was made based on direct feedback from a large customer comprising a significant portion of the class.
[4] For example, because weather was colder than normal on the peak day in January 2018, the weather-sensitive load on that day was greater than the weather-sensitive load on the peak day in January of the Forecasted Test Period.

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Generation Forecast Process

PPL companies

Generation Planning & Analysis
2018

Table of Contents

1 Introduction

The Generation Planning group annually prepares a generation and off-system sales ("OSS") forecast for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies"). This forecast provides the basis for – among other things – the Companies' forecasts of fuel costs, generation-related variable operating and maintenance costs, economy purchased power, and OSS margin. This document summarizes the process used to prepare the generation forecast.

2 Production Cost Model

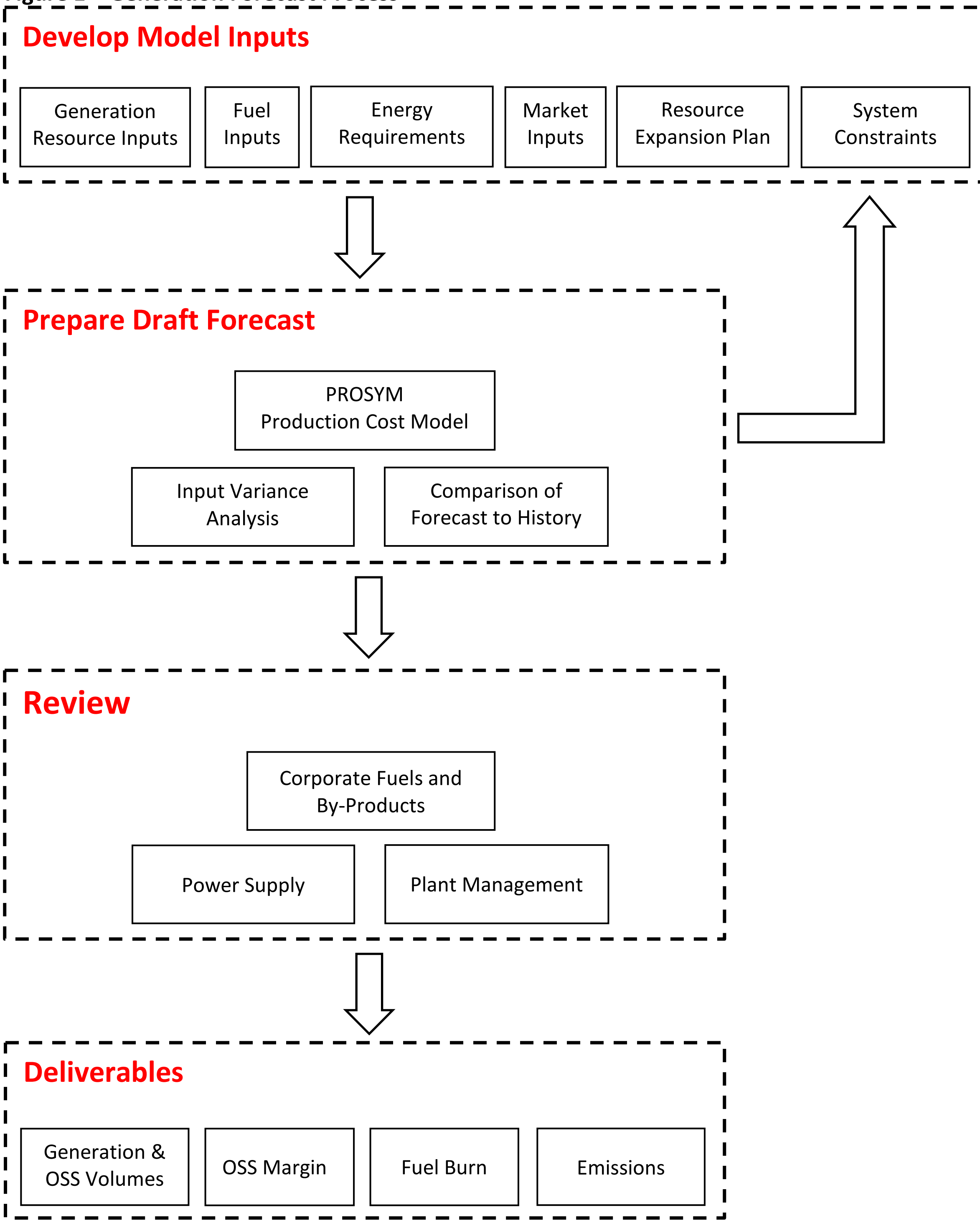
The Companies' generation forecast is developed using ABB's PROSYM, a proprietary production cost model. PROSYM is a chronological simulation engine that optimizes unit commitment and economic dispatch to meet the load for an interconnected electric system, considering the reserve requirements and other aspects of the electric system. PROSYM is a proven production cost model that has been used by utilities throughout the United States for decades.

In addition to PROSYM, SAS, Microsoft Access, and Microsoft Excel are used to process and analyze forecast results. Presentations containing forecast assumptions and results are prepared using Microsoft PowerPoint.

3 Process Overview

Figure 1 provides an overview of the process used to develop the Companies' generation forecast. In the first part of the process, model inputs are developed. Then, the model inputs are loaded into PROSYM and a draft generation forecast is prepared. PROSYM is a complex model, so extensive review takes place to ensure that the inputs are correctly loaded into the model and that the model results are reasonable. An input variance analysis evaluates the impact of changing each input or group of related inputs to ensure that the associated output changes are reasonable. Then, various elements of the generation forecast are compared to historical trends for reasonableness. If the forecast results are not deemed reasonable, the applicable model inputs are adjusted and the process is repeated. In the third part of the process, the results of the forecast are reviewed by other departments. This review process ensures that the forecast considers feedback from a broad range of perspectives. After all parties are satisfied with the results, the generation forecast is finalized and distributed to the groups who use the forecast to prepare financial budgets. Each part of this process is discussed further in the following sections.

Figure 1 – Generation Forecast Process



3.1 Develop Model Inputs

The first part of the process used to develop the Companies' generation forecast involves developing and vetting model inputs. Well-vetted inputs are essential to a good forecast. Wherever possible (and applicable), model inputs are initially developed based on an analysis of historical data. Then, these inputs are reviewed with plant management for reasonableness. Model inputs are adjusted when historical trends are not expected to continue in the future. Table 1 lists the six main categories of model inputs along with the inputs in each category. Each of these categories is discussed further in the following sections.

Table 1 - Key Inputs to the Generation Forecast

Input Category	Inputs
Generation Resource Inputs	Minimum and maximum capacity, heat rate, emission rates, variable operating and maintenance cost, operating limits, unit availability, company allocation
Fuel Inputs	Coal prices, natural gas prices, oil prices, other fuel-related inputs
Energy Requirements	Hourly energy requirements
Market Inputs	Electricity prices, emission allowance prices, off-system sales and purchase limits, off-system sales and purchase price thresholds
Expansion Plan Inputs	Timing and type of expansion plan units
System Constraints	Transmission constraints, spinning reserve requirements, off-system sales constraints, dispatch order rules

3.1.1 Generation Resource Inputs

The generation resources modeled in PROSYM include the Companies' existing and (if applicable) planned generation resources. Generation resources include generating units owned by the Companies, power purchase agreements with other power producers, and the capacity associated with the Companies' curtailable service rider ("CSR") customers.

Generation resource inputs define the operating characteristics of the generation resources. These inputs include the resource's minimum and maximum capacity, heat rate, emission rates, variable operating and maintenance cost, operating limits, equivalent forced outage rate, and ownership ratio. Each of these inputs is discussed further in the following sections.

3.1.1.1 Minimum and Maximum Capacity

The minimum and maximum capacity (or output) is specified for each generation resource as a megawatt ("MW") value for the summer, winter, fall, and spring seasons. Capacity inputs are specified based on an analysis of historical data and unit rating tests but rarely change materially from forecast to forecast.

3.1.1.2 Heat Rate

The heat rate specifies the amount of fuel required to produce a megawatt-hour ("MWh") of electricity. Where applicable, a heat rate curve is specified for each generation resource for the summer, winter, fall, and spring seasons. The heat rate curves are specified based on an analysis of historical data and heat rate tests performed by the plants.

3.1.1.3 Emission Rates

Where applicable, PROSYM models the emissions of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), and carbon dioxide ("CO_2") for each generation resource:

- SO_2 Emissions: For coal units, SO_2 emissions are modeled as a function of the unit's SO_2 removal rate and the sulfur content of the fuel. The SO_2 removal rate for each coal unit ranges between

91.5% and 99.2%, depending on the vintage of the unit's flue-gas desulfurization ("FGD") equipment.[1] The SO_2 removal rate is specified based on an analysis of historical data and updated in the forecast period for units being retrofitted with new or upgraded FGD equipment. The sulfur content of the fuel is provided by the Corporate Fuels and By-Products group. For gas units, SO_2 emissions are modeled as a function of an average SO_2 emission rate (specified in lb/MMBtu). The SO_2 emission rate for gas units is estimated by the unit manufacturer.

- NO_x Emissions: For coal units, NO_x emissions are modeled as a function of a NO_x emission curve (specified in lb/MMBtu). NO_x emissions vary seasonally and with the unit's generation output and are lower for units retrofitted with selective catalytic reduction ("SCR") equipment. The NO_x emission curve is specified based on an analysis of historical data in conjunction with performance expectations associated with the timing of catalyst replacement. Cane Run 7's NO_x emission rate is specified based on an analysis of historical data. For other gas units, NO_x emissions are modeled as a function of an average emission rate (also specified in lb/MMBtu) estimated by the unit manufacturer.
- CO_2 Emissions: CO_2 emissions are modeled as a function of the unit's average CO_2 emission rate (specified in lb/MMBtu). Average CO_2 emission rates are dependent on the type of fuel burned in the unit and are based on engineering estimates.

3.1.1.4 Variable Operating and Maintenance Cost

Variable operating and maintenance ("O&M") costs include all incremental non-fuel costs that are incurred when operating the generation resource. For coal units, variable O&M includes the cost of operating environmental controls. For Cane Run 7, variable O&M includes the cost of its long-term program contract ("LTPC"), which is paid quarterly based on the number of starts and operating hours for the unit. For simple-cycle combustion turbines ("SCCTs"), the cost of major maintenance is considered in unit commitment and dispatch decisions but is not modeled as a component of production costs.

3.1.1.5 Operating Limits

The following operating limits are modeled in PROYSM for each generation resource. Each of these inputs is specified based on operational experience.

- Minimum Down-Time: Minimum down-time is the minimum number of hours after coming offline that a generation resource must remain offline before it can be brought back online.
- Minimum Up-Time: Minimum up-time is the minimum number of hours after coming online that a generation resource must remain online before it can be taken offline for economic reasons.
- Ramp-Up Rate: Ramp-up rate is the rate (specified in MW/hour) at which a generation resource can increase its output.
- Ramp-Down Rate: Ramp-down rate is the rate (specified in MW/hour) at which a generation resource can decrease its output.

3.1.1.6 Unit Availability

The following unit availability inputs are modeled in PROSYM for each resource. These inputs determine the extent a resource is available for operation.

- Planned Maintenance Schedule: The planned maintenance schedule specifies the timing and duration of planned maintenance events. The schedule is developed with input from plant

[1] Brown Units 1-3 share the same FGD. Mill Creek Units 1-2 also share the same FGD.

management, Generation Dispatch, and Project Engineering, such that the outages will have the least economic and reliability impact to customers.

- Equivalent Unplanned Outage Rate ("EUOR"): EUOR inputs determine the amount of time the generation resource is unavailable due either to a forced outage or maintenance outage. EUOR inputs are specified based on an analysis of historical data.

3.1.1.7 Company Allocation

The energy and capacity for all generation resources modeled in PROSYM are either wholly or jointly allocated to LG&E and/or KU. For each generation resource, the Companies' allocation is specified in PROSYM to facilitate the process of creating generation and other forecasts by company as well as forecasting the After-the-Fact Billing process used to calculate the Fuel Adjustment Clause.

3.1.2 Fuel Inputs

Each thermal generation resource is associated with one or more fuel forecasts for startup and for online operation. The fuel inputs in PROSYM specify the cost of fuel, the fuel's heat content, the quantity of fuel required for startup, and – for generation resources where the fuel price is a blend of multiple fuel forecasts – the blend ratio of each fuel forecast. For coal, the fuel inputs also include the fuel's SO_2 content.

3.1.2.1 Coal Prices

A forecast of delivered coal prices is developed for each station by the Corporate Fuels and By-products group. These forecasts reflect the cost curve for the Companies' contracted coal volumes, the assumed cost of coal that will be contracted in the future, and the cost of transporting fuel from mines to the stations. Based on the coal burn forecast by unit, the Corporate Fuels and By-Products group calculates the target coal purchase tonnage needed each year to maintain desired inventory levels while meeting the forecasted coal burn. The forecasted price per MMBtu for each coal type is the result of computing the volume weighted average of the price of coal already under contract and the market price of coal. In the first five years of the forecast, the market price is a blend of coal bids received, but not under contract, and the forecast from an independent third party consultant, IHS. Beyond the fifth year, prices are increased at the compound annual growth rate reflected in the Energy Information Administration's latest Annual Energy Outlook for "All Coals, Minemouth" price forecast.

3.1.2.2 Natural Gas Prices

A forecast of Henry Hub natural gas prices is developed as a starting point for undelivered gas. The initial years of the Henry Hub price forecast reflect monthly forward market prices from NYMEX as of a specific recent quote date, which reflects a current view of forward prices at the time the forecast is prepared. In the subsequent years, the market prices are blended with the EIA's price forecast published in its most recent Annual Energy Outlook. The Henry Hub forward market prices are then adjusted to local delivered prices to KU and LG&E units using an average annual loss factor and a variable O&M charge per MMBtu, which also adjusts for average assumed basis differentials. For each station that uses natural gas for startup or online operations, a forecast of delivered natural gas prices is developed by adding transportation costs and a cost for pipeline losses to the forecast of Henry Hub prices.

3.1.2.3 Oil Prices

A forecast of delivered oil prices is developed for coal units that use fuel oil for startup and for SCCTs that can use fuel oil for online operation as an alternative to natural gas. The fuel oil price forecast consists of market prices in the short term that are then interpolated to a long-term forecast. The

Companies' delivered oil price forecast first uses NYMEX New York Harbor #2 fuel oil monthly contract settled prices as far out in time as there is some market liquidity.

Long-term #2 fuel oil prices are developed by applying the historical relationship between New York Harbor #2 fuel oil and West Texas Intermediate ("WTI") oil prices to forecasted WTI prices derived from IHS Global Insight's latest 30-year macro forecast. To integrate the two forecast periods, the short-term market-based fuel oil price forecast is interpolated to the long-term regression-based price forecast. The forecasted #2 fuel oil prices are then multiplied by the historical average ratio of the Companies' fuel purchase price to the New York Harbor #2 fuel oil price to arrive at the Companies' delivered fuel oil purchase price forecast.

3.1.2.4 Other Fuel-Related Inputs

Other fuel inputs include the fuel blend ratio, the quantity of startup fuel, the fuel's heat content, and fuel's SO_2 content.

- Fuel Blend Ratio – Trimble County 2 burns a blend of Illinois Basin coal and Powder River Basin coals. Because the prices of these coals are specified in separate forecasts in PROSYM, the fuel blend ratio determines the weighting that is used to compute the price of coal for Trimble County 2.
- Quantity of Startup Fuel – For each generating unit, the startup fuel quantity is the amount of fuel required to start the unit. These inputs are specified based on an analysis of historical data with input from plant management.
- Heat Content and SO_2 Content – Fuel heat and SO_2 contents are provided by the Corporate Fuels and By-products group.

3.1.3 Energy Requirements

PROSYM simulates the dispatch of the Companies' generating units to meet hourly energy requirements. The forecast of hourly energy requirements, which consists of native load sales and transmission and distribution losses, is developed by the Sales Analysis and Forecasting group. See the Electric Sales & Demand Forecast Process document for a discussion of the process used to develop the Companies' forecast of hourly energy requirements.

3.1.4 Market Inputs

Market inputs define the market in which the Companies operate. These inputs include spot hourly wholesale electricity prices, emission allowance prices, hourly OSS and economy purchase volume limits, and OSS and economy purchase price threshold values. Together, these inputs determine when the model should make economy purchases or OSS. Each of the market inputs is discussed in the following sections.

3.1.4.1 Electricity Prices

A forecast of spot hourly electricity prices is developed to model the Companies' interactions with the electricity market. The Companies buy and sell electricity primarily with PJM through the PJM-South Import ("PJM-SI") interface / pricing point which is used in the planning process to represent the electricity market.[2] In the initial years, monthly forward market prices for PJM West Hub ("PJM-WH")[3] quoted by Intercontinental Exchange as of a specific recent quote date are used as a basis for

[2] The Companies also transact electricity with counterparties other than PJM. The Companies model PJM as a representative market, considering liquidity and availability of market data.
[3] The PJM market is used as a proxy for all markets available to the Companies because most of the Companies' off-system sales and purchases are expected to be transacted with the PJM market.

developing an hourly forecast of PJM-SI prices, reflecting the most current view of forward prices at the time the forecast was prepared.[4] In the subsequent years, the market prices are interpolated to a long-term PJM-WH forecast developed using EPIS's AuroraXMP software, a proprietary electricity market model. Monthly PJM-SI prices are derived by applying seasonal discount factors by peak type to the PJM-WH prices. The discount factors are based on historical ratios between actual PJM-SI and PJM-WH spot prices.

Monthly average PJM-SI prices are shaped to daily average prices by peak type by maintaining a correlation between the Companies' forecasted daily average energy and the forecasted daily average electricity price in each month, based on their historical correlation. This relationship serves as a proxy for the correlation between the daily load level in the PJM market and the corresponding daily average electricity price. The daily average prices are derived by multiplying the forecasted monthly average prices (by peak type) by a daily weighting that reflects the correlated variances between forecasted daily vs. average monthly loads and forecasted daily vs. average monthly electricity prices, based on historical observations. Hourly prices are then derived by multiplying the daily prices by hourly price multipliers that reflect the historical average ratios of hourly prices to daily prices by month and by peak type.

3.1.4.2 Emission Allowance Prices

The dispatch cost for each unit includes the unit's fuel cost, variable O&M costs, and the cost of emission allowances. Emission allowance price forecasts are developed for SO_2, ozone seasonal NO_x, and annual NO_x emission allowances. Initial prices reflect market prices as of a specific recent quote date for allowances under the Cross-State Air Pollution Rule. Longer-term prices reflect those in IHS Energy's most recent long-term planning scenario. No CO_2 emission allowance price assumptions are made for the Clean Power Plan because of the uncertainty regarding its future status.

3.1.4.3 Hourly Off-System Sales and Purchase Volume Limits

The OSS and purchase limit inputs determine the maximum quantity (in MW) of OSS and economy purchases that can be made in any given hour. Since the volatility of available transmission capacity cannot be effectively modeled in PROSYM, limits on hourly OSS and economy purchases are used to align the volume of modeled OSS and economy purchase transactions with recent historical experience.

3.1.4.4 Off-System Sales and Purchase Price Thresholds

When making an OSS or economy purchase, the Companies incur various costs related to the transaction. These costs are referred to as OSS and purchase "thresholds." OSS and purchase thresholds include the cost of transmission and transmission losses, independent system operator balancing charges, and a risk premium the Companies' Power Supply group uses to manage the uncertainty that exists between real-time prices and aggregated hourly (or settled) prices.

3.1.5 Resource Expansion Plan Inputs

The expansion plan inputs specify the timing and type of generation resources planned, if any, to be added to the Companies' generation portfolio to meet customers' need for energy and capacity. These generation resources can take the form of new generating units or power purchase agreements with a third-party provider. Generation resource inputs are discussed in Section 3.1.1.

[4] The quoted "off-peak wrap" forward prices for PJM-WH are split into off-peak (7x8) and weekend (2x16) peak types using historical ratios.

3.1.6 System Constraints
PROSYM enables the user to model a variety of physical constraints that exist within the Companies' transmission system and generation portfolio. These constraints are discussed in the following sections.

3.1.6.1 Transmission Constraints
The Companies' transmission and distribution system is designed to deliver electricity from generation resources to load under a variety of circumstances. Despite the flexibility that is afforded the Companies, some constraints can occur in real time. For example, there are limits to the energy that can flow from LG&E to KU. PROSYM enables the Companies to model this and other transmission constraints.

3.1.6.2 Spinning Reserve Requirements
As a NERC balancing area, the Companies are required to carry contingency reserves to ensure the reliability of the grid. To meet these obligations in a least-cost manner, the Companies are party to a reserve sharing agreement with TVA. By sharing reserves with TVA, the Companies are able to reduce the amount of contingency reserves they need to carry. In the current plan, the Companies need to maintain 250 MW of contingency reserves at all times. In addition, the Companies typically carry approximately 75 MW of regulating reserves to follow load fluctuations in real time. PROSYM models these reserve requirements.

3.1.6.3 Off-System Sale Constraints
As a general rule, because hourly market prices can fluctuate, potential OSS margins from SCCTs do not justify the wear and tear associated with starting a unit in anticipation of potential OSS margins. Therefore, the Companies' SCCTs are generally only committed to meet customers' need for peak energy. For this reason, a constraint is modeled in PROSYM that reduces OSS by limiting modeled OSS when SCCTs are operating, which results in a proportion of OSS from SCCTs in line with historical volumes.

3.1.6.4 Dispatch Order Rules
Dispatch order rules determine the order in which different types of generation resources are dispatched. The majority of generation resources are dispatched economically. However, curtailment of the Companies' CSR customers is limited to times when most or all other company-owned resources have been or are being dispatched. Likewise, the Companies' reserve sharing agreement gives the Companies limited and temporary access to emergency reserves that can only be dispatched after all other resources have been exhausted. The dispatch order rules enable the Companies to model these constraints.

3.2 Prepare Draft Generation Forecast
In the second part of the process used to develop the Companies' generation forecast, model inputs are loaded into PROSYM and PROSYM is used to prepare a draft generation forecast. PROSYM is a complex model, so extensive review takes place to ensure that the inputs are correctly loaded and that the model results are reasonable. An input variance analysis evaluates the impact of changing each input or group of related inputs to ensure that the associated output changes are reasonable. Then, various elements of the generation forecast are compared to historical trends for reasonableness. The input variance analysis and comparison of the forecast to history are discussed in more detail in the following sections.

3.2.1 Input Variance Analysis

The process of performing an input variance analysis begins with the previous year's generation forecast and is completed in steps. As each input or group of inputs is updated, PROSYM is used to create a new forecast. A comparison of forecast results in each step reveals the impact of changing each input (or group of related inputs) incrementally. The comparison of forecast results for each step includes a comparison of native load production costs, OSS margin, generation volumes, unit capacity factors, fuel burn, and other factors. In most cases, the change from the previous year's forecast to the current year's forecast is explained primarily by a limited number of factors. Despite this fact, the impact of all input changes is evaluated carefully. If the impact of a change is not deemed reasonable, the model inputs are adjusted and the process is repeated.

3.2.2 Comparison of Forecast to History

The goal of the generation forecasting process is to produce the most accurate forecast possible. In addition to the input variance analysis, numerous elements of the forecast are compared to historical trends to further assess the reasonableness of the forecast. In many cases, the forecast should be consistent with historical trends. When this is not the case, it is important to ensure that forecasted deviations from historical trends are reasonable. The following is a sample of forecast elements that are compared to historical data.

- Annual/monthly/hourly generation by generation resource
- Annual/monthly fuel burn by generation resource
- Annual startup fuel by generation resource
- Annual SCCT starts/run hours
- Annual/monthly/hourly OSS volumes by peak type
- Annual/monthly/hourly OSS margin by peak type
- Annual/monthly/hourly economy purchase volumes by peak type
- Annual SO_2/NO_x emissions
- Annual/monthly capacity factor by generation resource
- Annual/monthly intercompany transaction volumes
- Annual/monthly dispatch order

3.3 Review

In the third part of the process used to develop the Companies' generation forecast, the results of the forecast are reviewed by other departments. This review process ensures that the forecast considers feedback from a broad range of perspectives.

The following groups are primary consumers of the forecast results and review various elements of the forecast to help ensure that the results are reasonable:

- Corporate Fuels and By-products: The Corporate Fuels and By-Products group reviews the fuel burn forecast by generating station and fuel type.
- Power Supply: The Power Supply group reviews the forecasts of OSS margin, OSS volumes, and economy purchase volumes by peak type.
- Plant Management: Plant managers review the forecasts of generation by station and fuel type.

3.4 Deliverables

After forecast reviews are completed, the forecast deliverables are distributed to the groups within the company who use the forecast to prepare financial budgets. The following is a list of key deliverables:

- Generation Forecast
- Fuel Burn Forecast
- Fuel Expense Forecast
- OSS Margin Forecast
- Emissions Forecast

2019 Business Plan: Coal Inventory Limits and Generation & OSS Forecast

Generation Planning & Analysis
June 14, 2018

Case Nos. 2018-00294 and 2018-00295
Attachment to Filing Requirement
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Coal Inventory Limits

No proposed changes to coal inventory limits in the 2019 Plan

	2018 BP				2019 BP				Increase (Decrease)			
	Min		Max		Min		Max		Min		Max	
	Tons (000)	Days	Tons (000)	Days	Tons (000)	Days	Tons (000)	Days	Tons (000)	Days	Tons (000)	Days
Ghent	425	20	810	38	425	20	810	38	0	0	0	0
Mill Creek	290	20	600	41	290	20	600	41	0	0	0	0
Trimble	250	21	520	43	250	21	520	43	0	0	0	0
Brown	130	30	250	57	130	30	250	57	0	0	0	0
System	**1,095**	**21**	**2,180**	**42**	**1,095**	**21**	**2,180**	**42**	**0**	**0**	**0**	**0**

- Waiver requirements are based on highlighted inventory limits
- Non-highlighted values are guidelines to be used within the Fuels group
- Brown's limits reflect BR 1-2 retirement on Feb. 28, 2019

Generation & OSS Forecast

2019 BP Summary

- Compared to the 2018 BP, native load production costs ($/MWh) are notably lower in the 2019 BP; OSS contribution is higher in 2019 and lower in 2020-2022
  - Lower fuel prices, market electricity prices, and load drive differences throughout planning period

Native Load Production Costs[1] ($/MWh)	2019	2020	2021	2022	2023	CAGR
2018 BP[2]	22.93	22.88	23.43	24.52	25.42	2.6%
2019 BP	22.46	22.57	23.07	23.70	24.21	1.9%

OSS Contribution (100%, $M)	2019	2020	2021	2022	2023
2018 BP	1.0	2.4	4.2	5.1	6.8
2019 BP	2.0	1.9	3.6	4.6	6.9

1) Includes variable fuel costs, consumables, purchases, and variable PPA costs

2) 2018 BP numbers have been adjusted to reflect exclusion of fixed coal transportation costs to better align with dispatched costs

Key planning assumptions & inputs

- Load, fuel prices, and electricity prices are generally lower Plan-over-Plan

Plan-over-Plan Change (%)	2019	2020	2021	2022	2023
Native Load	-0.5%	-0.5%	-0.5%	-0.6%	-0.7%
Gas Prices (LKE Wgt Avg)[1]	-3.9%	-4.8%	-6.1%	-8.6%	-11.1%
Electricity Prices (PJM-SI ATC)	4.8%	-5.5%	-5.4%	-5.4%	-5.4%
Coal Prices (LKE Wgt Avg)[1]	-0.9%	-0.3%	0.3%	-1.6%	-2.1%

1) Fuel prices reflect variable delivered costs inclusive of contracted volumes

- Brown 1-2 are assumed to retire February 28, 2019
- Coal generating units are assumed to have a 65-year life for planning purposes

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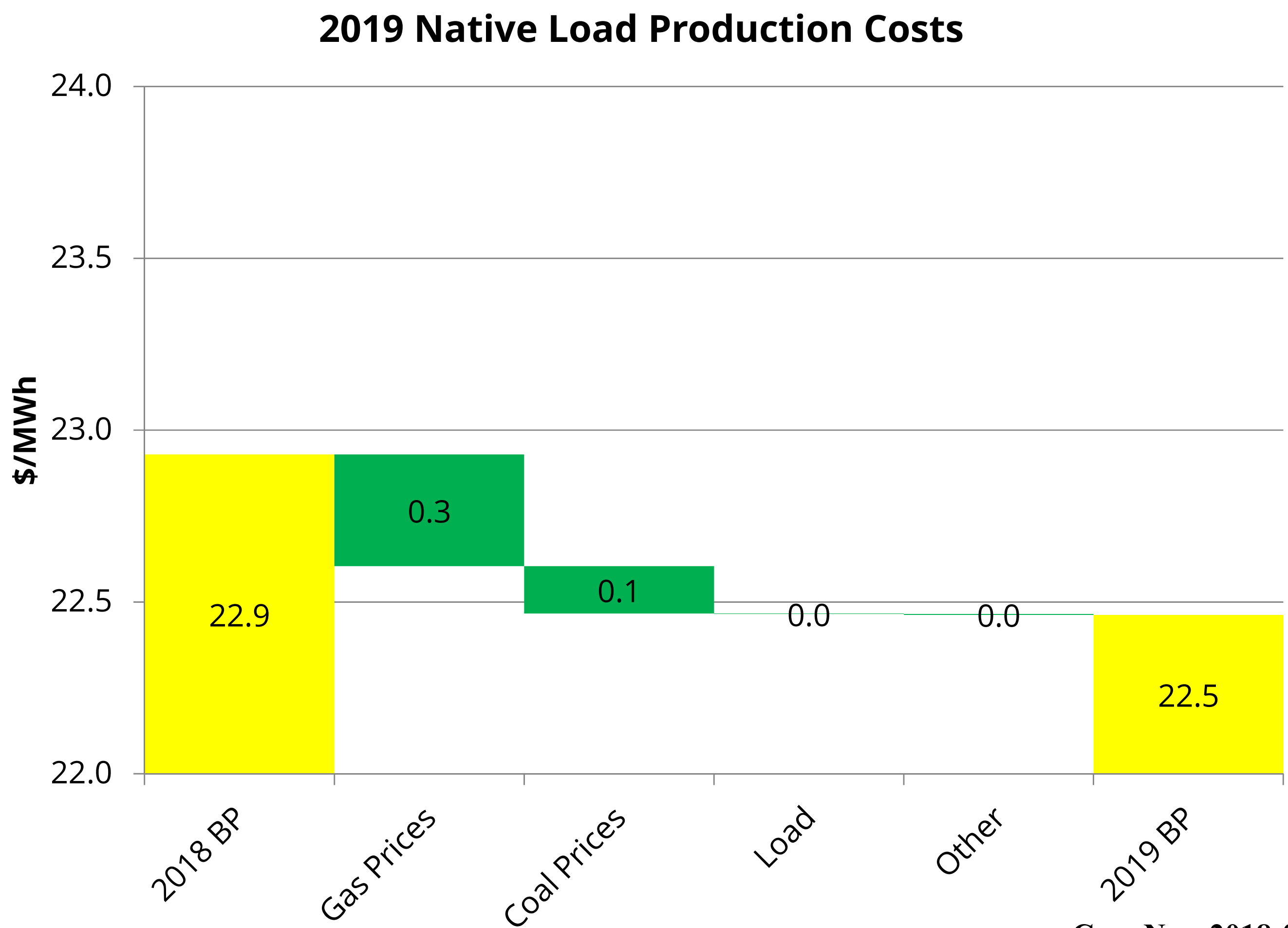
In 2019-2021, lower gas prices drive lower production costs



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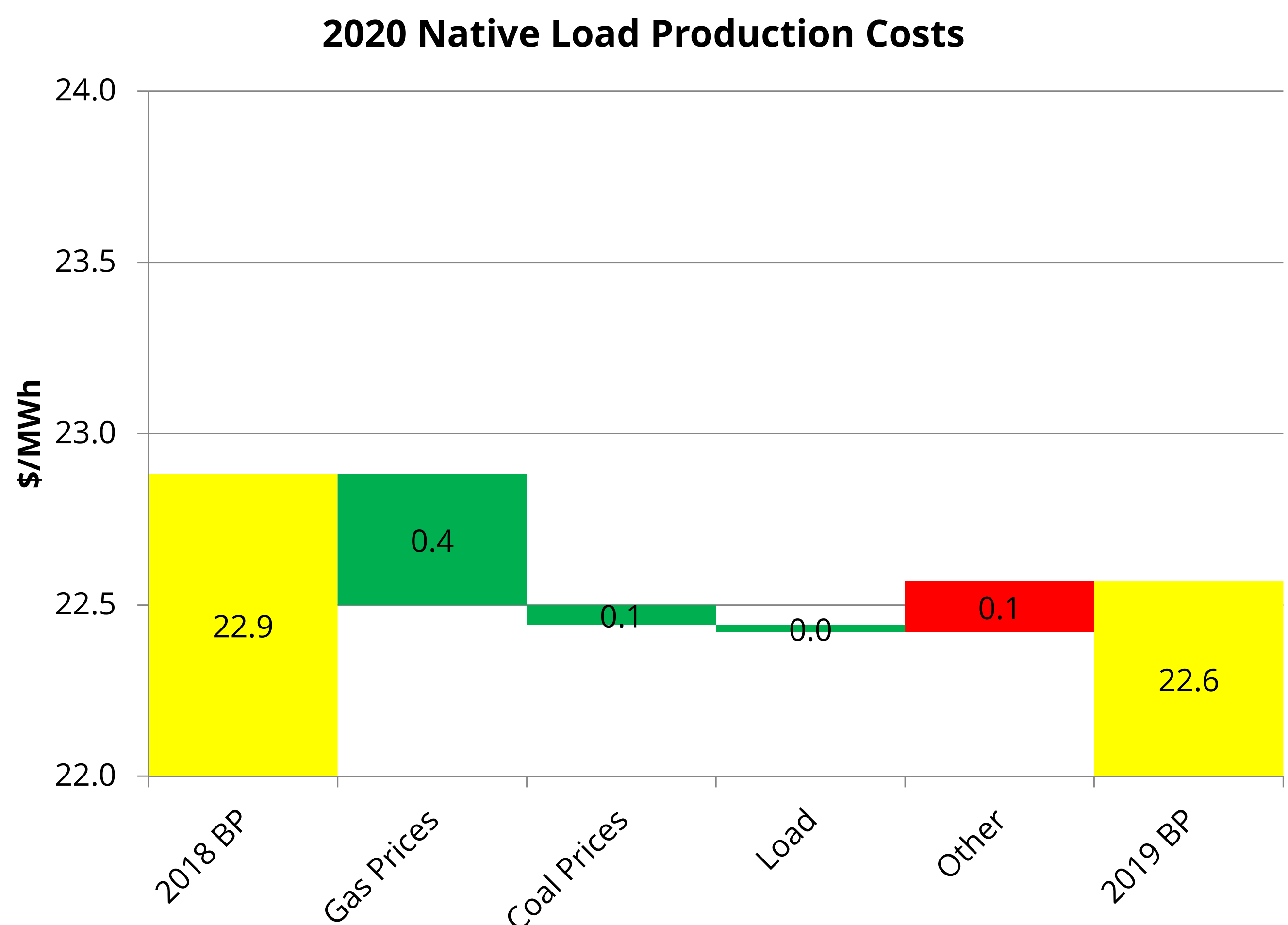
In 2019-2021, lower gas prices drive lower production costs



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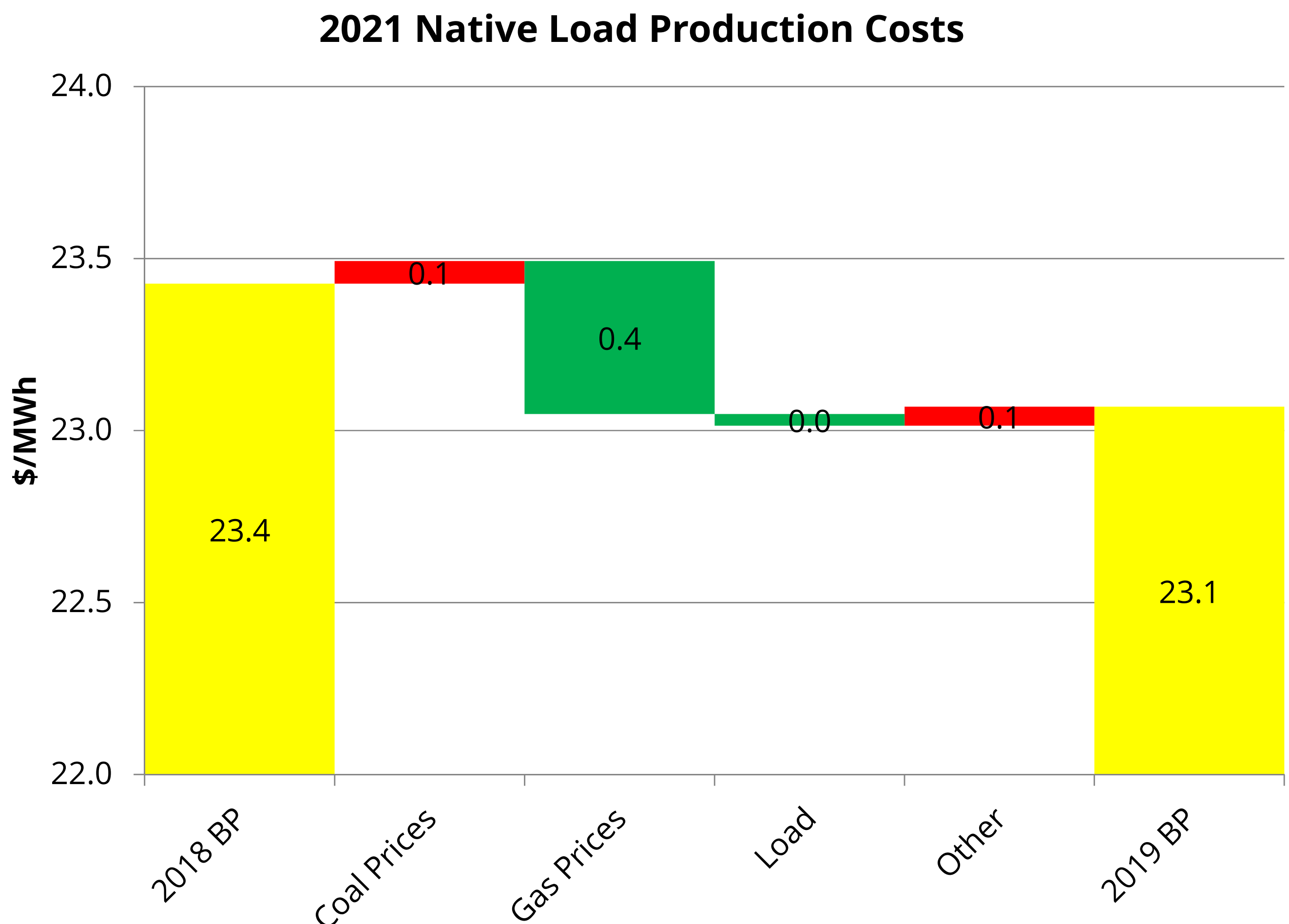
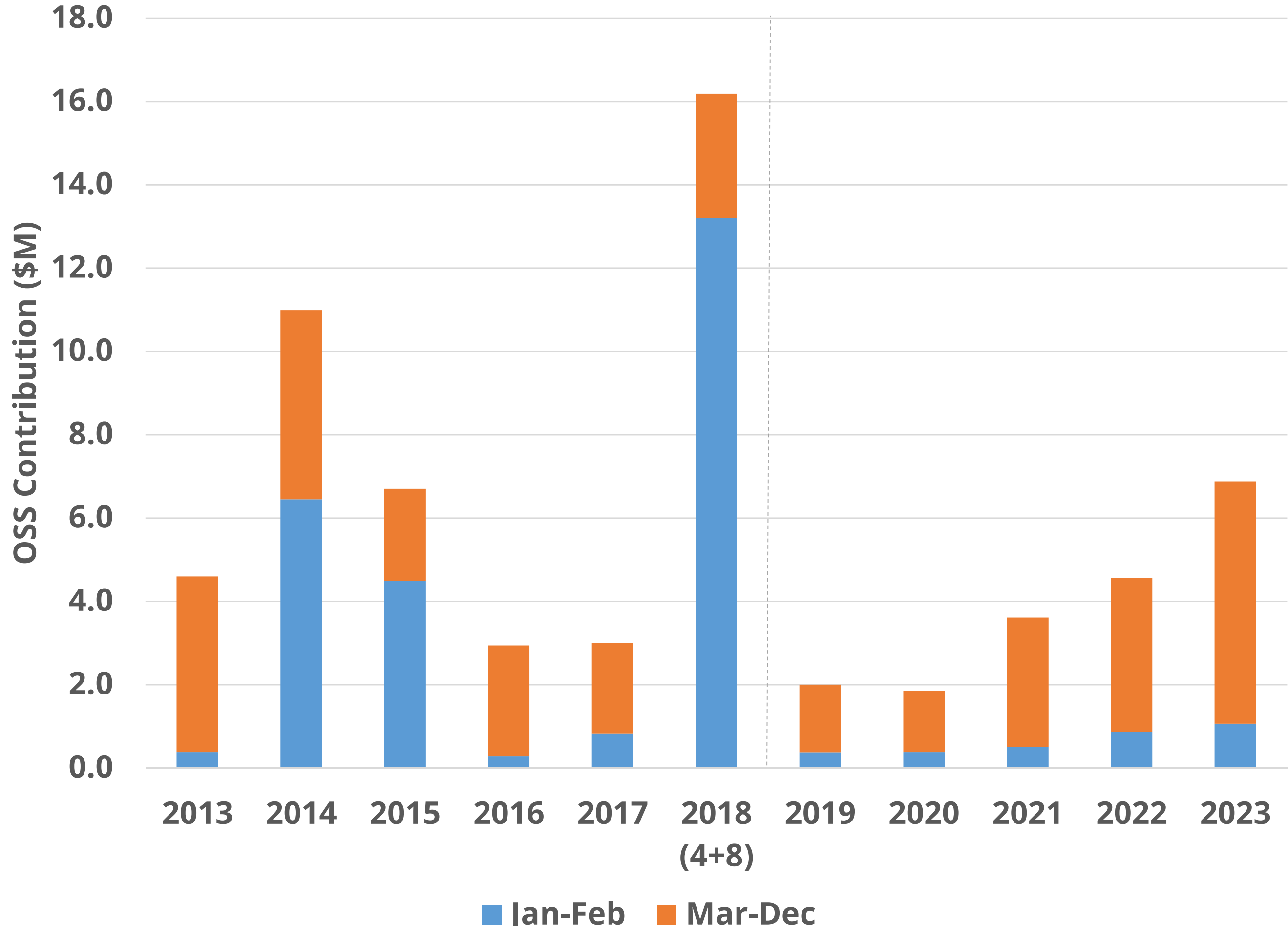
In 2019-2021, lower gas prices drive lower production costs



Higher OSS in 2014, 2015, and 2018 was result of extreme winter conditions; forecasted OSS reflect normal weather



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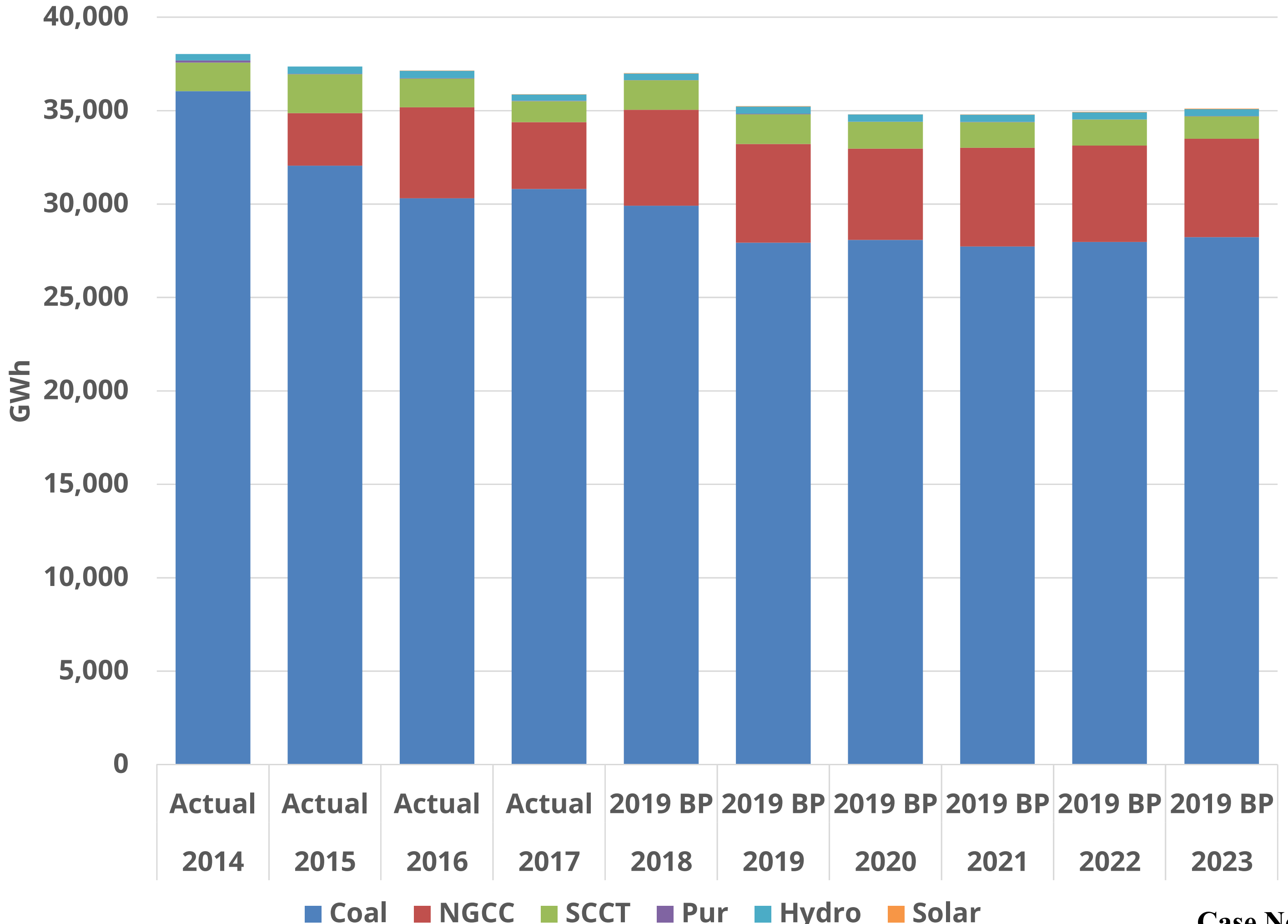
Energy mix in generating portfolio expected to remain consistent throughout the planning period



Year	Coal %
2014	95%
2015	86%
2016	82%
2017	86%
2018	81%
2019	79%
2020	81%
2021	80%
2022	80%
2023	80%

2019 BP in 2018: 4 + 8

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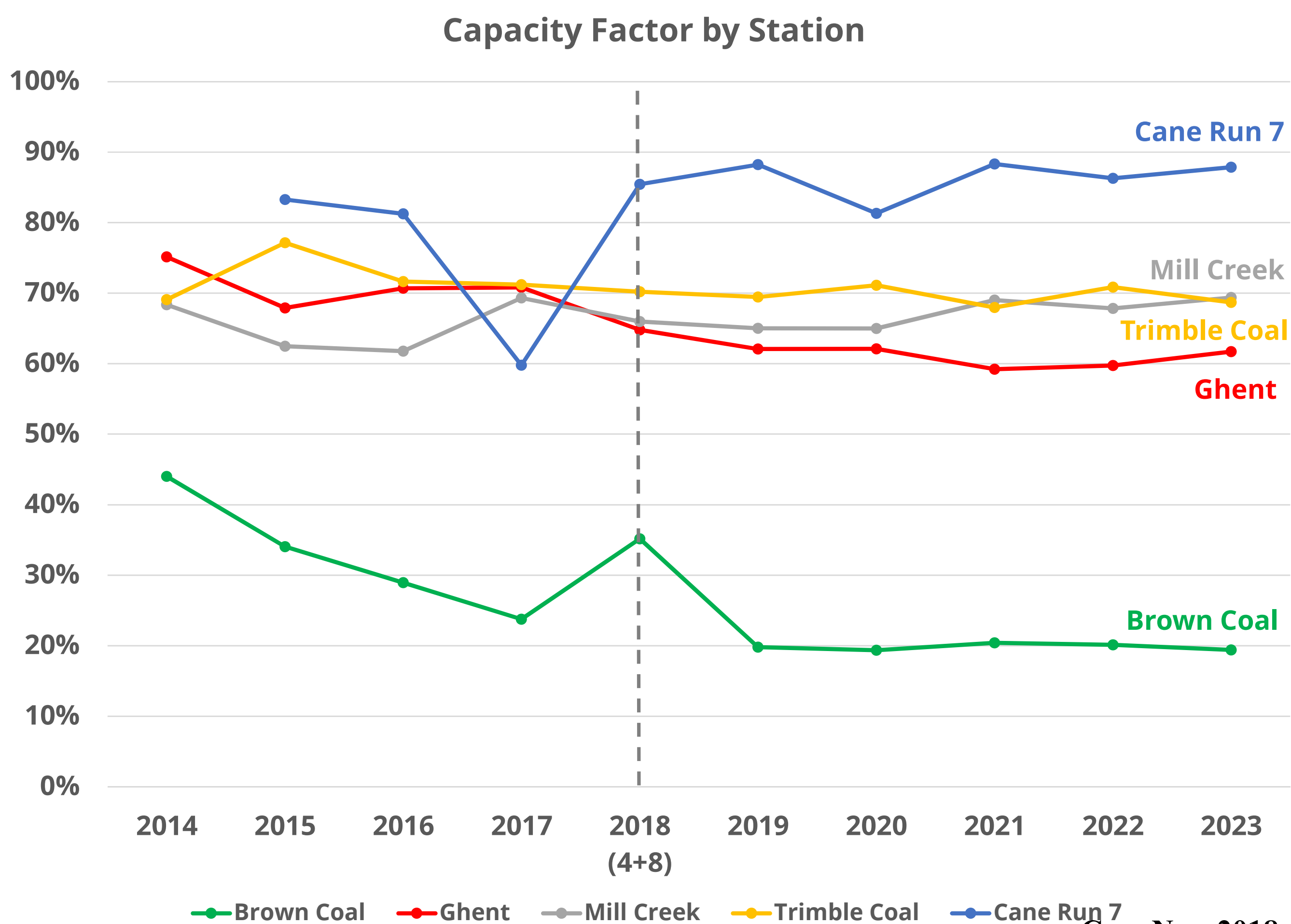
Capacity factor by station



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Summer reserve margin is 23% to 24% after retirement of Brown 1-2

Combined Company
Summer Reserve Margin Needs (MW)
based on 2019 Business Plan Load Forecast

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Peak Load before DSM	6,703	6,688	6,674	6,657	6,653	6,657	6,661	6,679	6,680	6,679
Direct Load Control (DLC)[1]	-96	-91	-87	-84	-80	-77	-73	-70	-67	-64
Other DSM	-247	-236	-236	-236	-236	-236	-236	-236	-236	-236
Net Peak Load	6,360	6,361	6,350	6,338	6,338	6,345	6,352	6,373	6,377	6,379
Existing Capability[2]	7,987	7,987	7,987	7,988	7,988	7,989	7,989	7,989	7,989	7,989
Retirements	-272	-272	-286	-286	-286	-286	-286	-286	-286	-286
CSR[3]	141	141	141	141	141	141	141	141	141	141
Total Supply	7,856	7,856	7,842	7,843	7,843	7,844	7,844	7,844	7,844	7,844
MW Margin	1,495	1,495	1,491	1,505	1,505	1,499	1,492	1,471	1,466	1,464
Reserve Margin %	**23.5%**	**23.5%**	**23.5%**	**23.7%**	**23.7%**	**23.6%**	**23.5%**	**23.1%**	**23.0%**	**23.0%**

1) DLC reflects expected capacity under average peak weather conditions
2) Includes OVEC
3) CSR reflects expected hourly curtailment, which differs from contracted curtailable load

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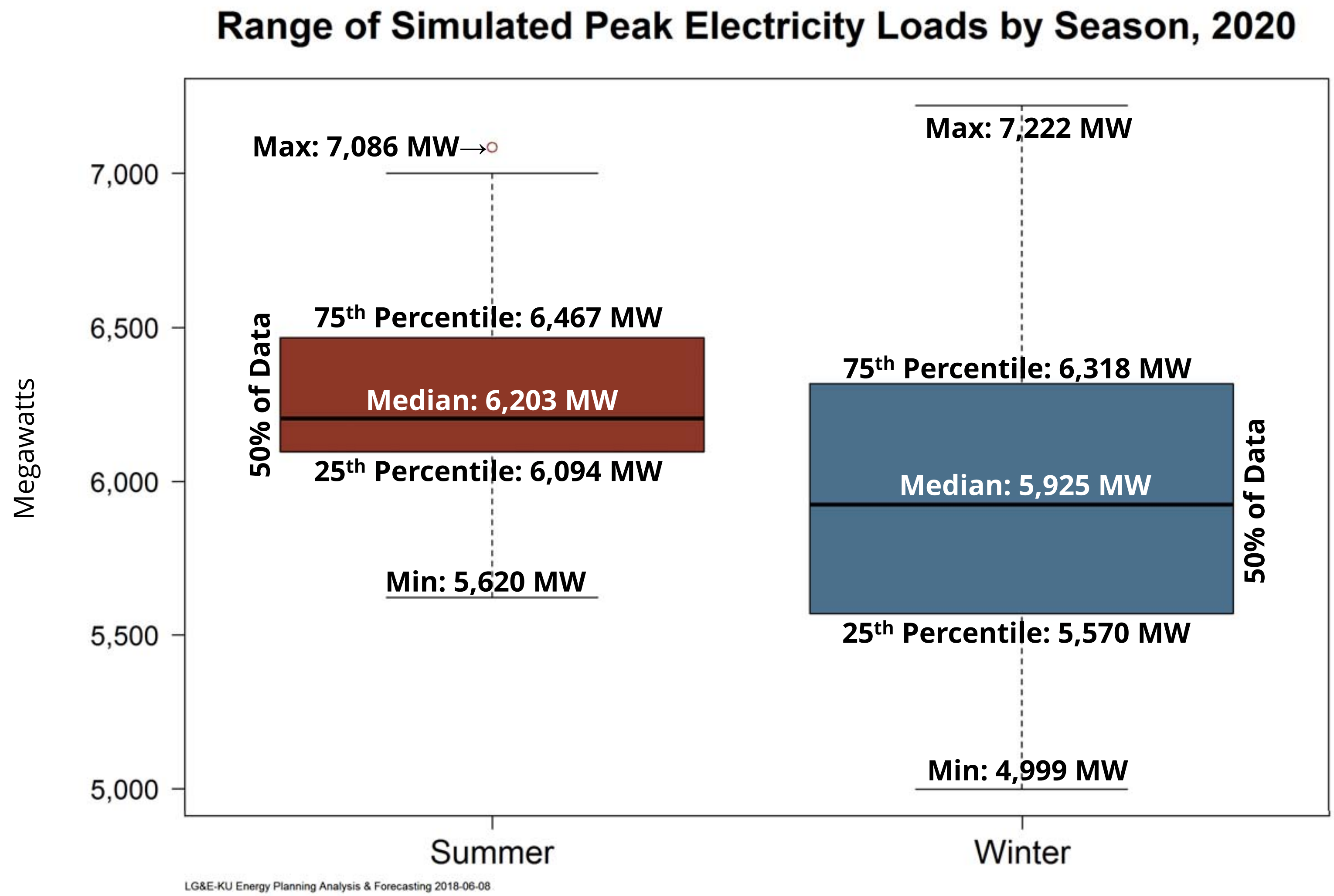
Volatility of winter peaks results in higher winter reserve margin need relative to summer



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Winter reserve margin is 33% to 37% after retirement of Brown 1-2; winter reserve margin target based on 1-in-10 LOLE standard is above 30%

Combined Company
Winter Reserve Margin Needs (MW)
based on 2019 Business Plan Load Forecast

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Net Peak Load	6,220	5,972	5,975	5,970	5,966	5,966	5,957	5,948	5,949	5,954
Existing Capability[1,2]	8,425	8,253	8,253	8,261	8,261	8,086	8,279	8,279	8,279	8,279
Retirements	0	-275	-291	-291	-291	-291	-291	-291	-291	-291
CSR[3]	141	141	141	141	141	141	141	141	141	141
Total Supply	8,566	8,119	8,103	8,111	8,111	7,936	8,129	8,129	8,129	8,129
MW Margin	2,346	2,147	2,128	2,141	2,144	1,969	2,172	2,180	2,180	2,175
Reserve Margin %	**37.7%**	**35.9%**	**35.6%**	**35.9%**	**35.9%**	**33.0%**	**36.5%**	**36.7%**	**36.6%**	**36.5%**

1) Includes OVEC and Bluegrass PPA; Bluegrass PPA expires on 4/30/2019
2) Reflects expected hot gas path maintenance outage for Paddy's Run 13 in 2024, which will make unit unavailable for that winter
3) CSR reflects expected hourly curtailment, which differs from contracted curtailable load

CSAPR II update

- NO_x emission rates are reflective of collaborative plan developed during 2017 BP
  - NO_x targets are being reviewed given updates since 2017 BP (lower load, lower gas prices, Brown 1-2 retirement); changes not anticipated for 2019 BP

- Current forecasts yield NO_x emissions above annual allowance allocations in near term (but well within banked volumes), and within allocations in long term

Key takeaways

- Lower native load costs yields lower costs for ratepayers
  - Projected production cost savings of $10-40M per year vs. 2018 BP
- Load forecast is flat; absent additional unit retirements or significant load growth, no need for new capacity
- CSAPR II compliance plan appears manageable through collaborative effort
  - Monitoring Jefferson County NAAQS attainment plan
- Cane Run 7 projected to be dispatched at a high capacity factor with low gas prices
- No expected impact to generation portfolio over the planning period due to future federal regulations

Appendix

2019 BP – Assumptions

- Modeled EFOR and MOR assumptions are based on historical values ('target' EFORs will continue to be the basis for KPI reporting)

- Retirements / expansion plan:
  - Bluegrass PPA (165 MW): May 2015 – April 2019
  - Brown 1-2 assumed to retire February 28, 2019
  - No expansion units planned at this time
  - Coal generating units are assumed to have a 65-year life for planning purposes

- Turbine overhaul schedule:
  - 2019: GH2, MC3, MC1, BR3
  - 2020: GH4
  - 2021: GH1
  - 2022: MC4
  - 2023: N/A

Coal generating units are assumed to have a 65-year life for planning purposes

Unit	Retirement w/ 65-Year Planning Assumption
Brown 1	2022[1]
Brown 2	2028[1]
Brown 3	2036
Mill Creek 1	2037
Ghent 1	2039
Mill Creek 2	2039
Ghent 2	2042
Mill Creek 3	2043
Ghent 3	2046
Mill Creek 4	2047
Ghent 4	2049
Trimble County 1	2055
Trimble County 2	2076

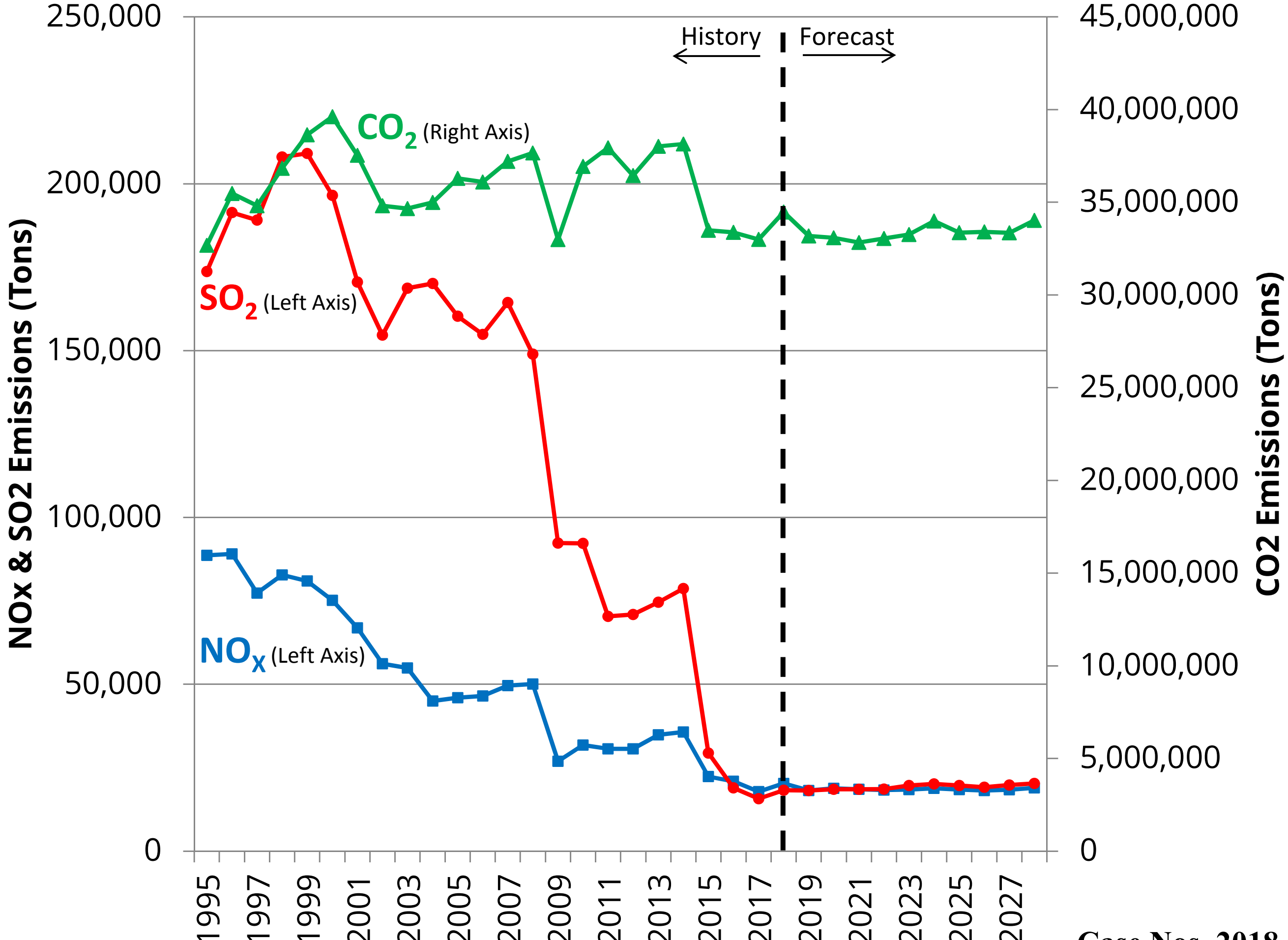
1) Brown 1-2 are assumed to retire on February 28, 2019 in the 2019 BP

Allowance price assumptions

CSAPR Emission Allowance Prices ($/ton emitted)

Year	Annual NO_x	Seasonal NO_x	SO_2
2019	2	84	1
2020	2	26	2
2021	2	66	2
2022	8	338	99
2023	6	218	46
2024	5	198	21
2025	4	180	10
2026	2	164	4
2027	1	149	2
2028	0	135	0

Emissions have decreased with addition of controls



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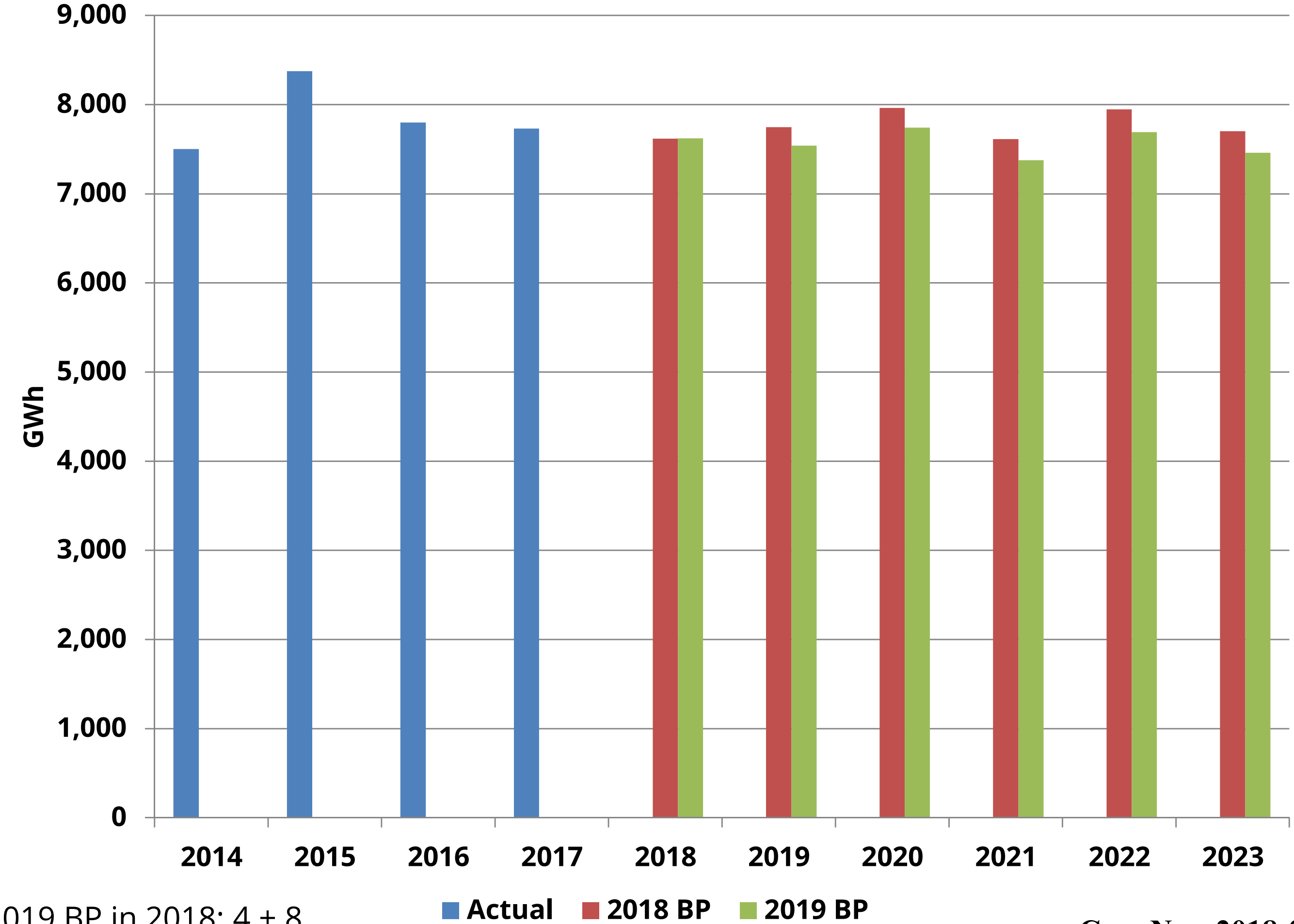
Trimble coal generation is lower mostly due to higher VOM consumables and updates to maintenance outage rates



2019 BP in 2018: 4 + 8
100% TC

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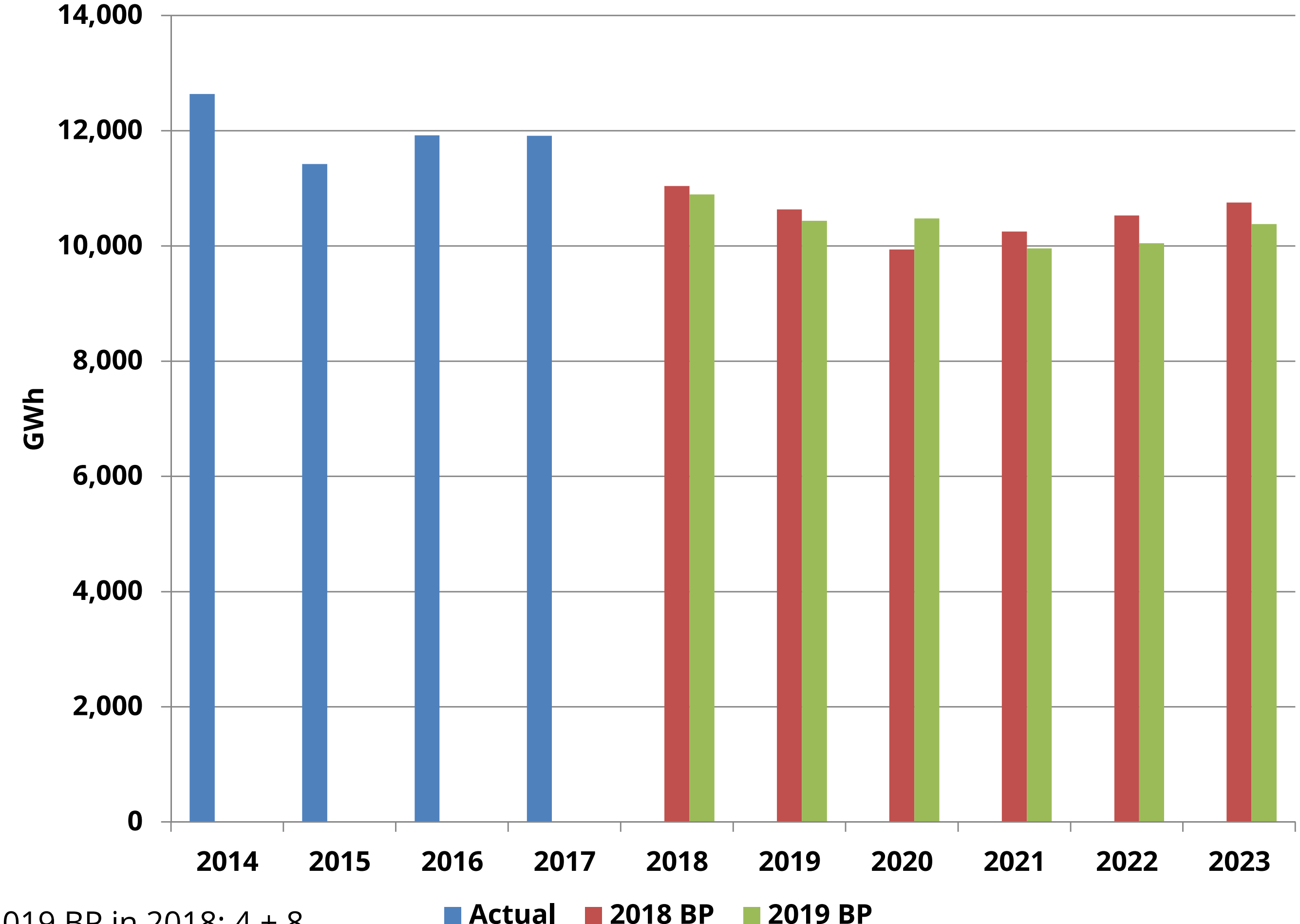
Ghent generation is lower mostly due to lower load, updated heat rates, and lower gas prices, but increases in 2020 due to favorable coal prices



2019 BP in 2018: 4 + 8

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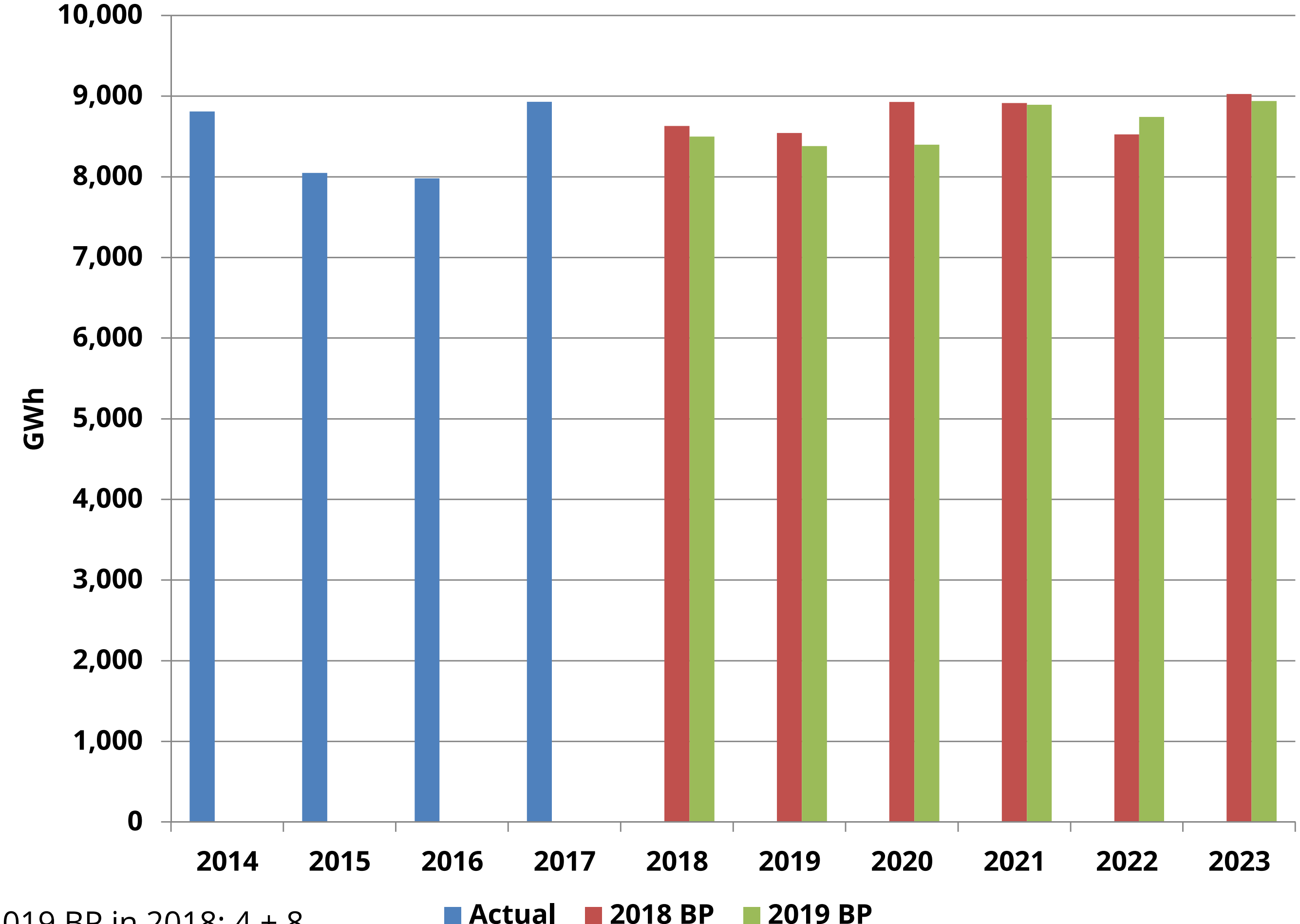
Mill Creek generation is lower in 2020, but higher in 2022-2023 mostly due to changes in coal prices



2019 BP in 2018: 4 + 8

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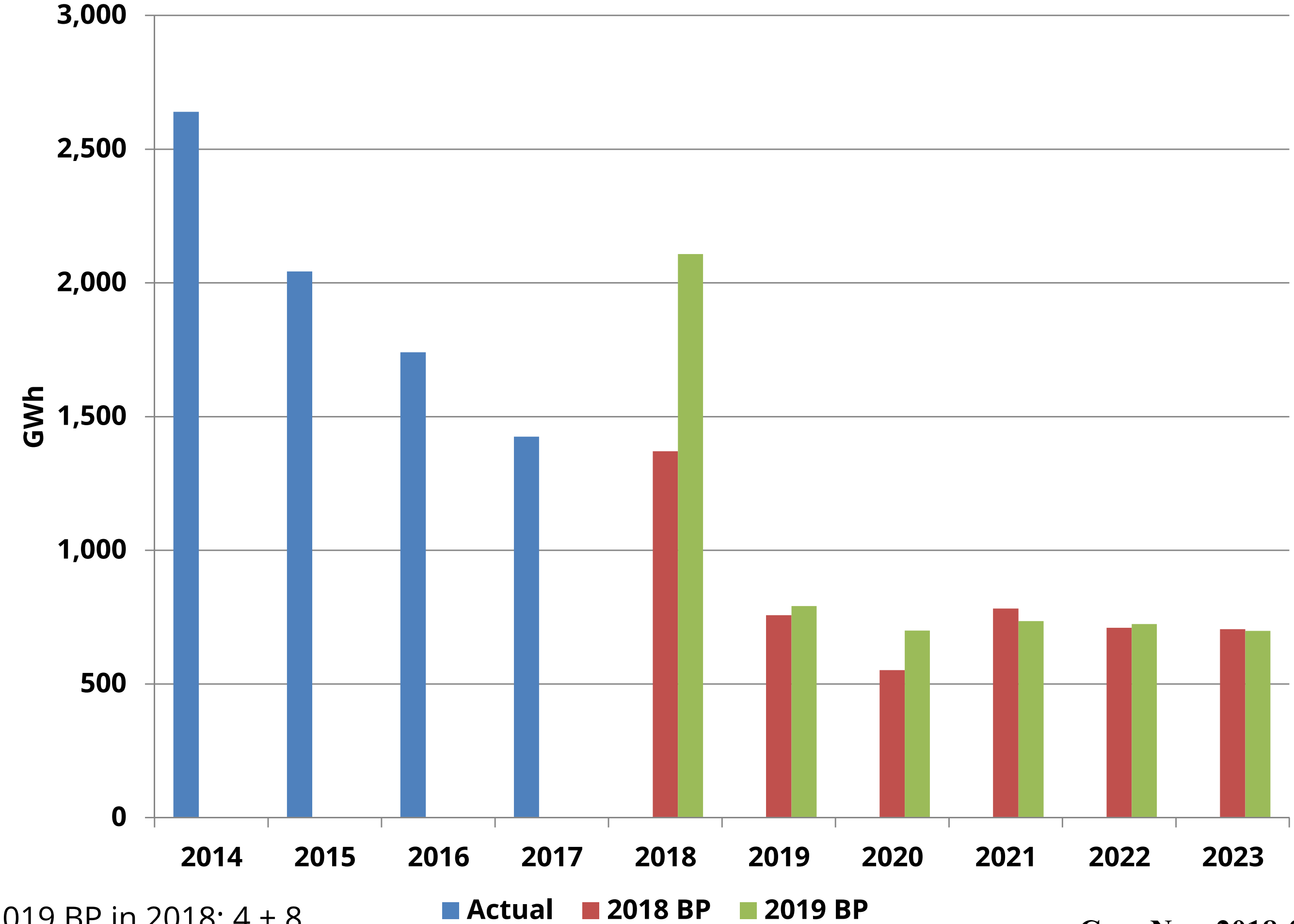
Brown coal generation reflects fairly consistent generation after Brown 1-2 retirement



2019 BP in 2018: 4 + 8

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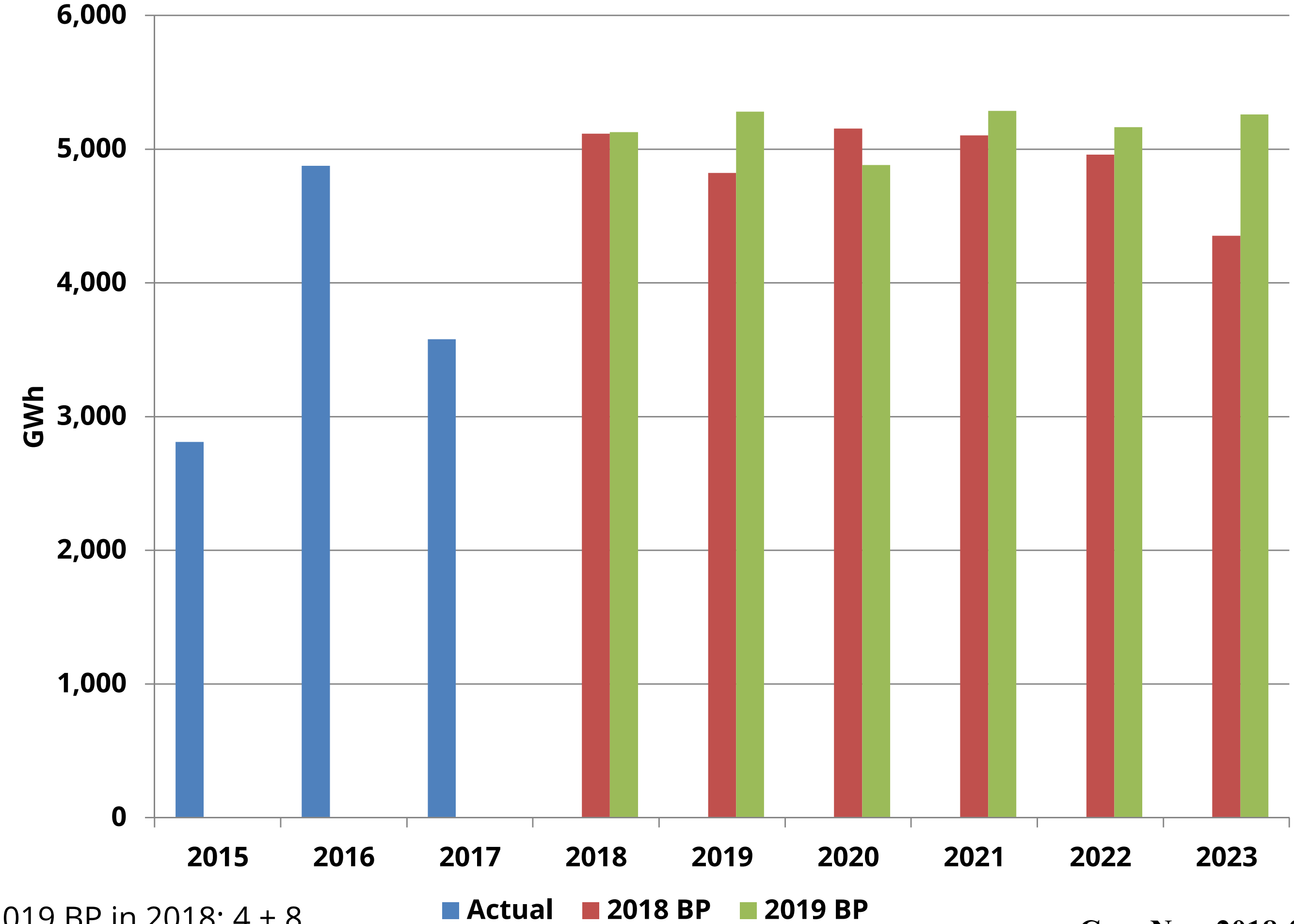
Cane Run 7 projected to be dispatched at a high capacity factor given expected gas prices; forecast changes reflect changes to planned maintenance



2019 BP in 2018: 4 + 8
CR7 commissioned in June 2015

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SCCT generation adjusted to better reflect historical allocation across stations

CT Generation *(GWh)*

	ACTUAL				(4+8)	2019 BP				
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
BR5, 8-11	124	430	466	179	176	238	193	182	177	133
BR6, 7	383	367	55	44	258	184	162	184	226	145
PR13	104	181	99	64	108	148	135	120	112	92
TC5-10	893	1,001	855	771	986	1,000	945	883	872	833
	1,504	**1,979**	**1,475**	**1,058**	**1,529**	**1,569**	**1,435**	**1,368**	**1,387**	**1,204**
						2018 BP				
						1,710	**1,456**	**1,333**	**1,384**	**1,511**

CT Starts *(# starts)*

	ACTUAL				(4+8)	2019 BP				
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
BR5, 8-11	150	384	399	205	189	204	214	167	184	161
BR6, 7	207	97	51	43	95	108	117	125	168	129
PR13	68	124	91	69	84	140	144	112	114	83
TC5-10	674	563	639	497	643	757	801	775	754	705
	1,099	**1,168**	**1,180**	**814**	**1,011**	**1,209**	**1,276**	**1,179**	**1,220**	**1,078**
						2018 BP				
						1,431	**1,330**	**1,270**	**1,199**	**1,334**

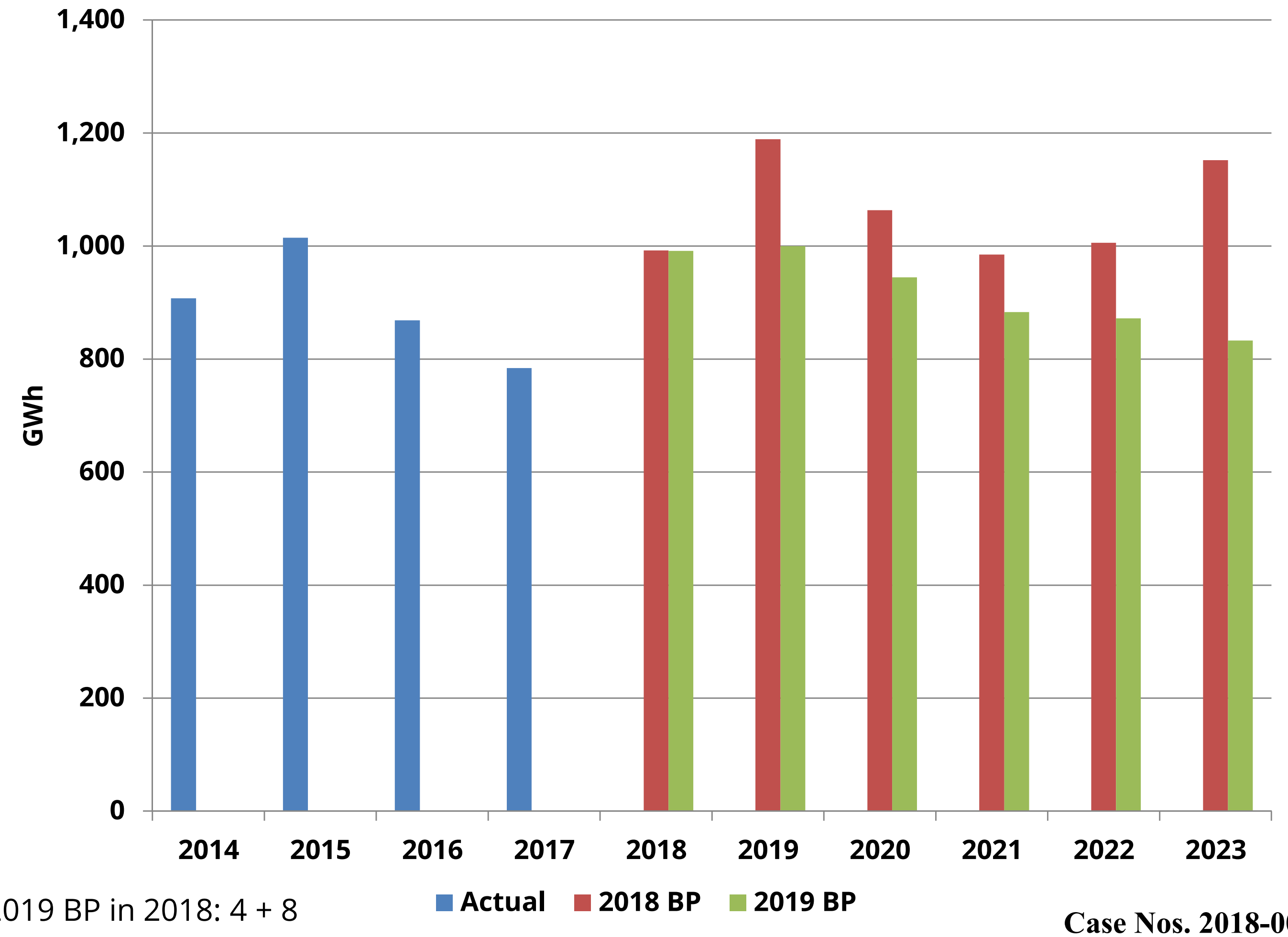
CT Generation (GWh)/Start

	ACTUAL				(4+8)	2019 BP				
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
BR5, 8-11	0.8	1.1	1.2	0.9	0.9	1.2	0.9	1.1	1.0	0.8
BR6, 7	1.9	3.8	1.1	1.0	2.7	1.7	1.4	1.5	1.3	1.1
PR13	1.5	1.5	1.1	0.9	1.3	1.1	0.9	1.1	1.0	1.1
TC5-10	1.3	1.8	1.3	1.6	1.5	1.3	1.2	1.1	1.2	1.2
	1.4	**1.7**	**1.2**	**1.3**	**1.5**	**1.3**	**1.1**	**1.2**	**1.1**	**1.1**
						2018 BP				
						1.2	**1.1**	**1.0**	**1.2**	**1.1**

CT Run Hours/Start

	ACTUAL				(4+8)	2019 BP				
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
BR5, 8-11	15.1	13.9	13.2	9.9	13.6	16.8	13.0	14.8	12.9	11.2
BR6, 7	18.7	29.0	8.9	8.2	20.3	11.6	9.5	10.1	9.3	7.8
PR13	12.0	10.9	8.1	8.1	9.7	7.1	6.4	7.0	6.6	7.4
TC5-10	13.4	12.6	10.2	12.5	11.3	8.3	7.4	7.2	7.3	7.5
	14.5	**14.2**	**11.0**	**11.3**	**12.4**	**9.9**	**8.4**	**8.6**	**8.3**	**8.1**
						2018 BP				
						9.1	**8.3**	**7.9**	**8.9**	**8.9**

Trimble CT generation is displaced by higher generation from Brown CTs and is more reflective of recent history



2019 BP in 2018: 4 + 8

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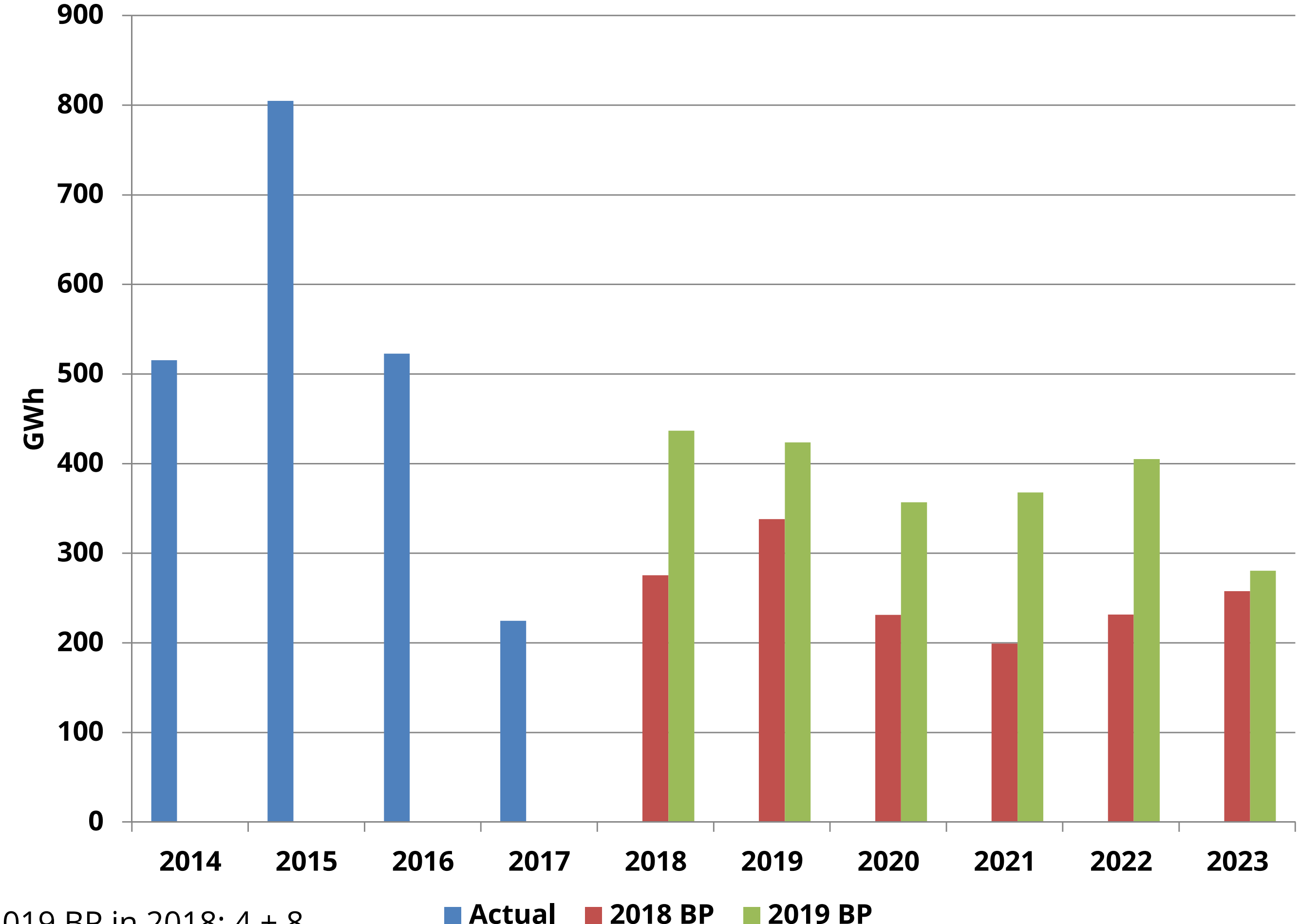
Higher Brown CT generation displaces Trimble and Paddy's Run generation and is more reflective of recent history



2019 BP in 2018: 4 + 8

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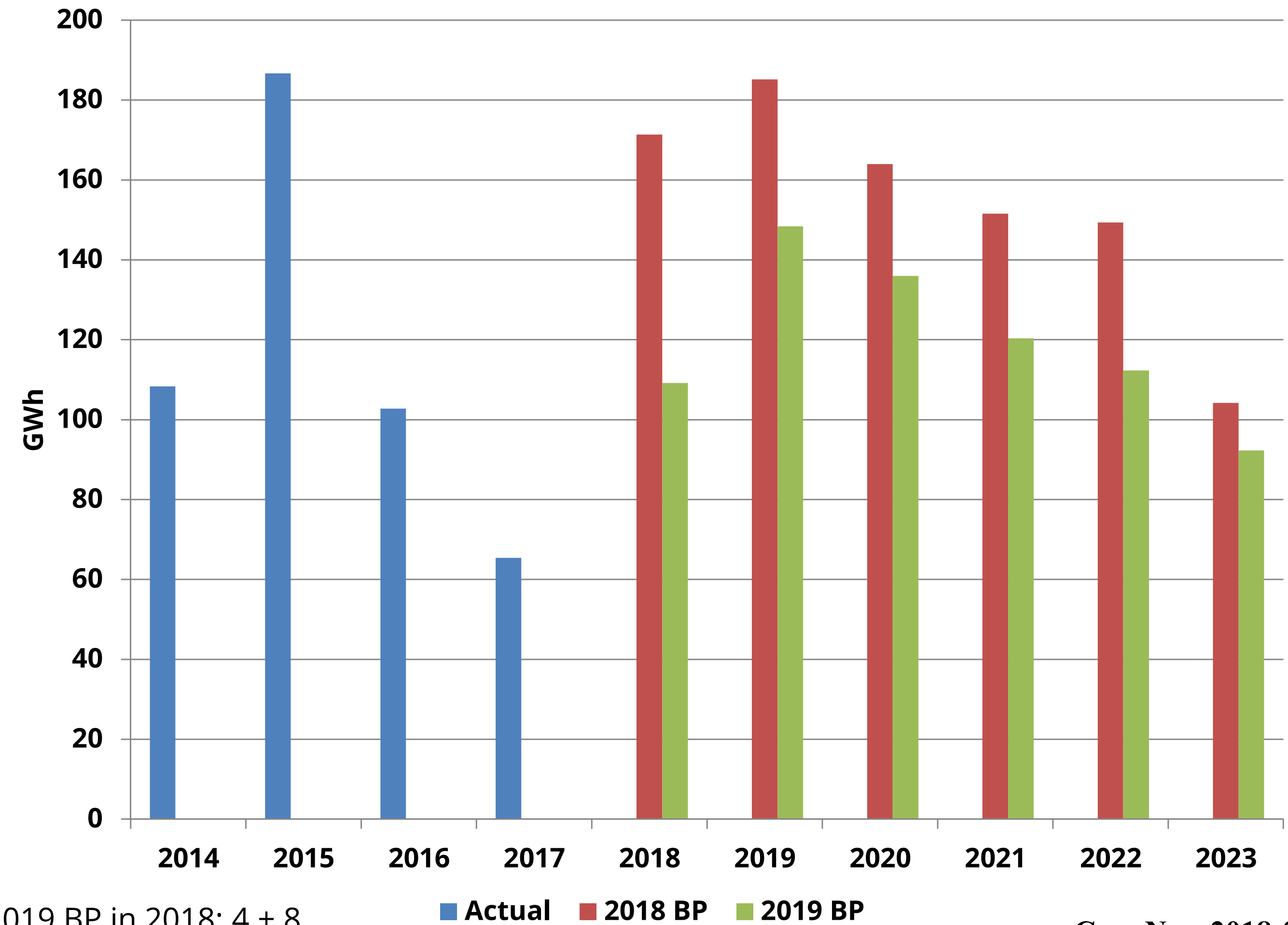
Paddy's Run generation is displaced by higher generation from Brown CTs and is more reflective of recent history



2019 BP in 2018: 4 + 8

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Seasonally-adjusted capacity factor by unit

	History				4+8	2018 BP					2019 BP				
(%)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
Brown 1	43	24	25	6	32	18	N/A	N/A	N/A	N/A	22	N/A	N/A	N/A	N/A
Brown 2	53	44	29	23	44	21	N/A	N/A	N/A	N/A	29	N/A	N/A	N/A	N/A
Brown 3	41	32	30	29	32	19	15	22	20	20	19	19	20	20	19
Ghent 1	77	60	73	74	67	71	64	60	65	68	65	64	56	59	64
Ghent 2	80	61	72	70	77	66	70	70	72	73	67	76	73	72	74
Ghent 3	73	72	64	61	52	53	49	53	53	52	54	54	51	51	50
Ghent 4	69	78	74	78	62	63	52	60	61	62	61	54	56	57	59
Mill Creek 1	77	57	69	64	74	65	77	72	75	72	61	68	67	72	67
Mill Creek 2	70	56	64	65	56	67	62	65	61	69	67	63	69	63	69
Mill Creek 3	77	65	58	76	71	61	73	69	71	69	59	68	68	75	69
Mill Creek 4	55	67	59	69	63	70	65	70	60	70	71	62	72	62	72
OVEC	57	49	55	52	50	41	37	37	43	47	50	49	49	49	49
Trimble County 1	84	67	83	67	78	71	75	69	75	71	72	73	67	74	72
Trimble County 2	59	84	64	74	65	71	72	71	72	71	68	70	69	69	67
Cane Run 7	N/A	83	81	60	85	81	86	85	83	73	88	81	88	86	88
Brown 5, 8-11	2	8	9	3	3	3	1.6	0.8	1.2	1.0	4	4	3	3	3
Brown 6-7	14	13	1.9	1.5	9	7	5	6	6	7	7	6	7	8	5
Paddy's Run 13	8	13	7	5	8	13	12	11	11	7	10	10	8	8	7
Trimble CTs	10	11	10	9	11	13	12	11	11	13	11	11	10	10	9
Bluegrass 3	N/A	8	2	3	4	3	N/A	N/A	N/A	N/A	3	N/A	N/A	N/A	N/A
Cane Run 11	0.2	0.5	0.1	0.1	0.1	0.2	0.4	0.2	0.2	0.2	0.5	0.3	0.2	0.2	0.0
Haefling 1-2	0.4	1.0	0.1	0.1	0.0	0.2	0.3	0.0	0.0	0.0	0.3	0.2	0.1	0.1	0.0
Paddy's Run 11	0.1	0.0	0.1	0.0	0.2	0.3	0.4	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.0
Paddy's Run 12	0.3	0.1	0.1	0.1	0.0	0.2	0.0	0.2	0.1	0.0	0.2	0.2	0.3	0.0	0.0
Zorn 1	0.1	0.9	0.1	0.1	0.2	0.3	0.3	0.0	0.0	0.0	0.3	0.2	0.0	0.0	0.0
Dix Dam	29	36	29	22	39	28	27	27	27	27	30	29	30	30	30
Ohio Falls	60	61	70	61	54	65	65	65	65	65	66	66	66	66	66
Brown Solar	N/A	N/A	22	20	21	22	22	22	22	22	21	21	21	21	21

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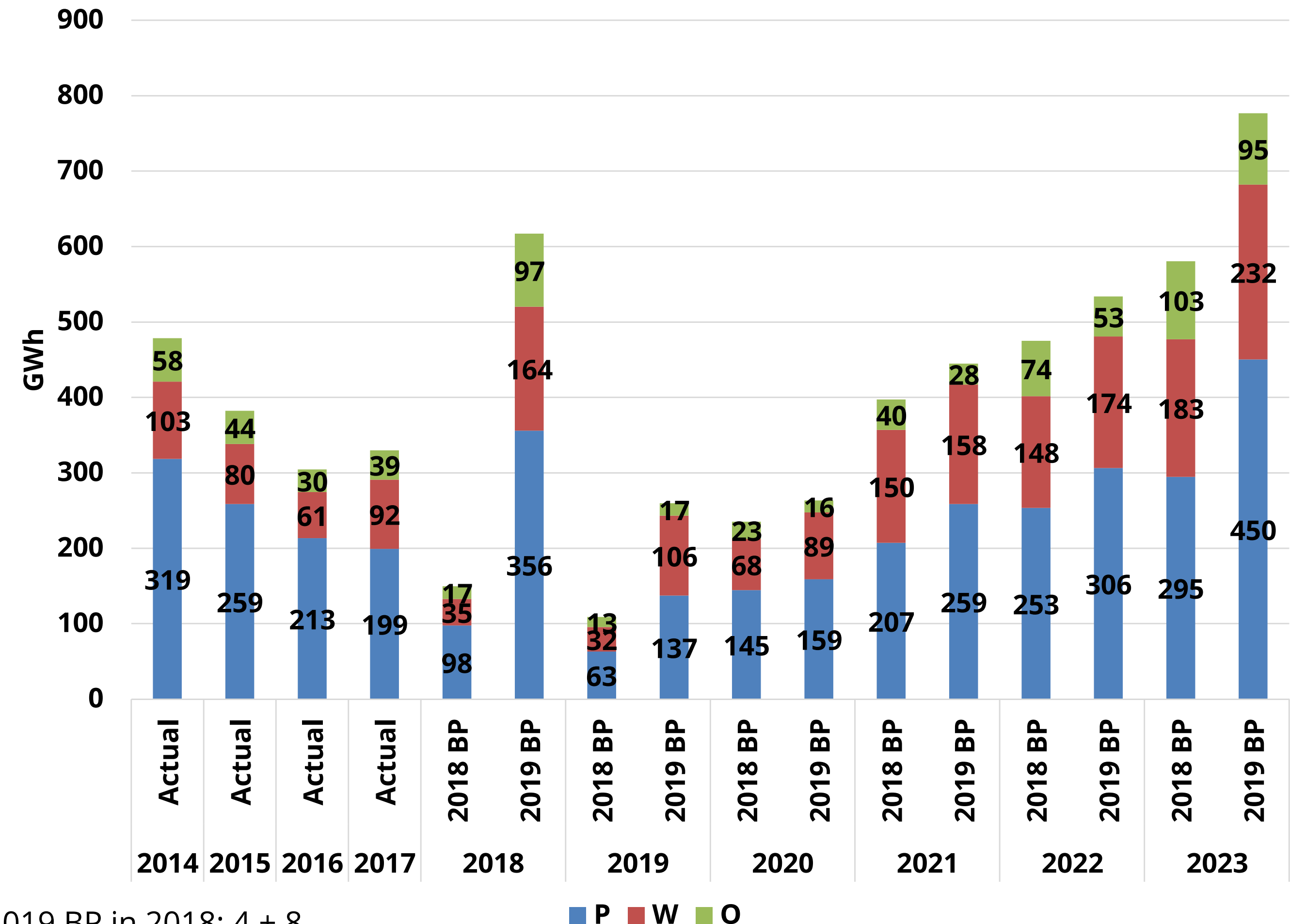
Unit rank by operating cost

	2019		2020		2021		2022		2023	
	2018 BP	2019 BP	2018 BP	2019 BP	2018 BP	2019 BP	2018 BP	2019 BP	2018 BP	2019 BP
Brown 1	14	14	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 2	13	13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 3	15	15	15	15	15	13	15	13	15	13
Cane Run 7	1	1	1	1	1	1	1	1	2	1
Ghent 1	9	9	9	9	9	9	9	9	9	9
Ghent 2	2	3	2	3	2	3	2	3	1	3
Ghent 3	11	11	11	11	11	11	11	11	11	11
Ghent 4	10	10	10	10	10	10	10	10	10	10
Mill Creek 1	4	6	3	5	3	6	3	5	4	6
Mill Creek 2	8	8	7	7	7	7	8	8	8	8
Mill Creek 3	7	7	6	8	6	8	7	7	6	7
Mill Creek 4	6	5	5	6	4	5	4	4	5	4
OVEC	12	12	12	12	12	12	12	12	12	12
Trimble County 1	5	4	4	4	5	4	5	6	3	5
Trimble County 2	3	2	8	2	8	2	6	2	7	2

OSS volumes by peak type



2019 BP in 2018: 4 + 8

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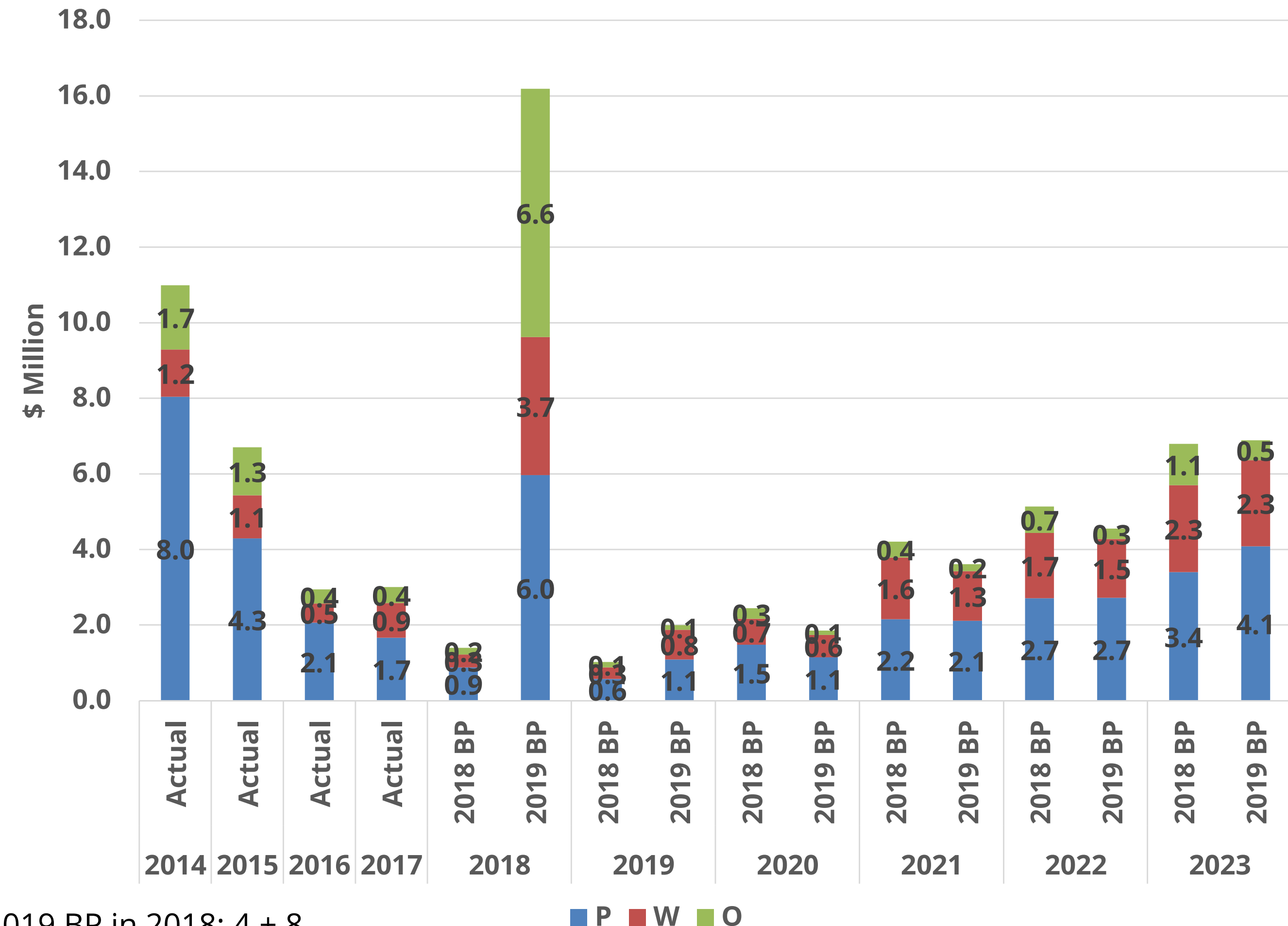
OSS contribution by peak type



2019 BP in 2018: 4 + 8

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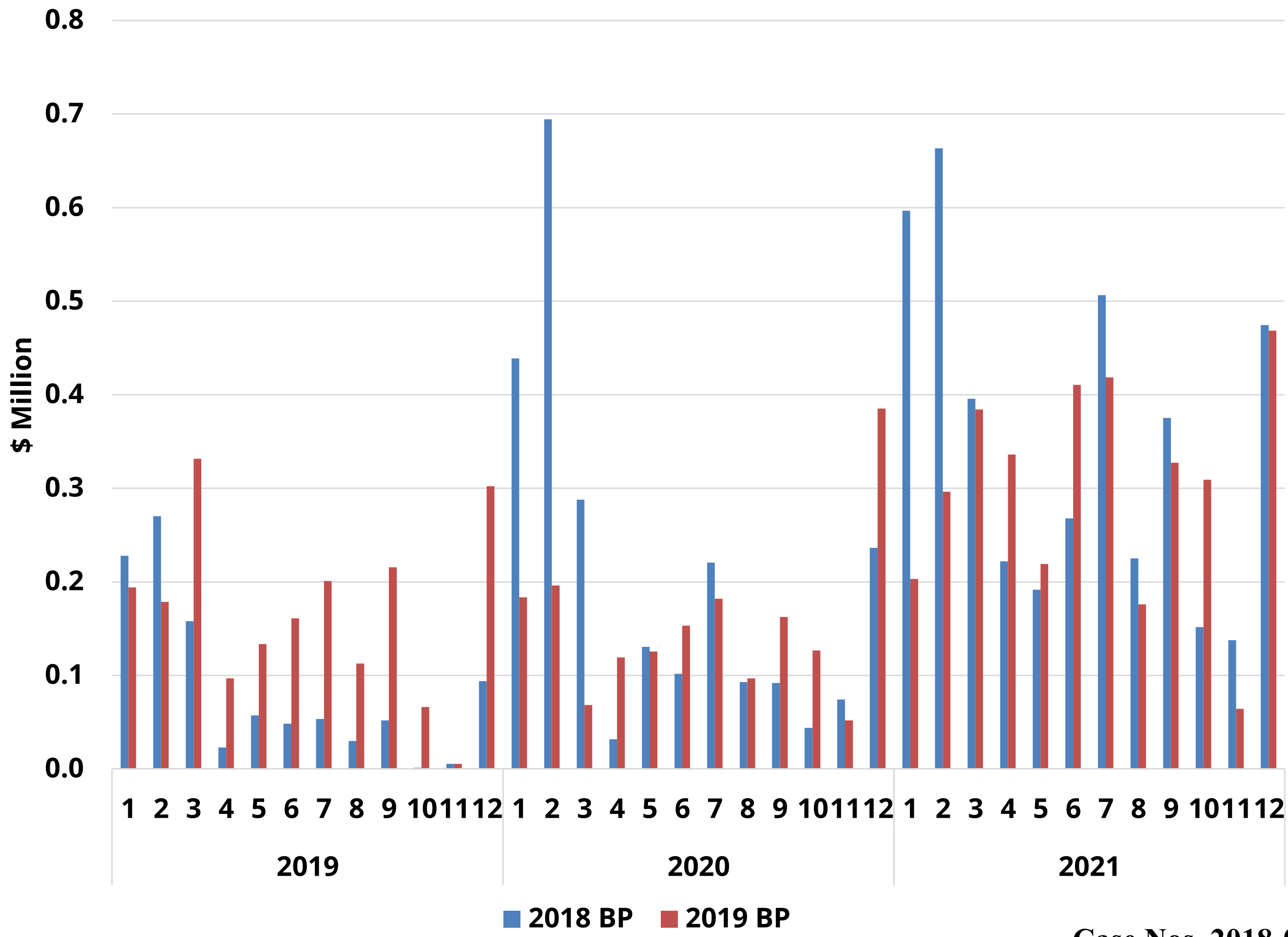
OSS contribution by month



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Variable O&M increases at Trimble, but decreases at other stations in 2019 BP largely due to Mercury O&M

Total VO&M ($/MWh)	2019			2020			2021			2022		
	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff
Brown 1	1.62	1.25	(0.37)	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Brown 2	1.48	1.11	(0.37)	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Brown 3	2.20	1.54	(0.67)	1.72	1.58	(0.14)	2.33	1.60	(0.73)	2.39	1.65	(0.74)
Ghent 1	2.04	1.83	(0.21)	2.11	1.91	(0.20)	2.15	1.95	(0.20)	2.19	1.99	(0.20)
Ghent 2	1.31	1.16	(0.15)	1.35	1.20	(0.15)	1.38	1.23	(0.15)	1.41	1.25	(0.16)
Ghent 3	1.99	1.80	(0.19)	2.06	1.87	(0.18)	2.09	1.91	(0.18)	2.13	1.95	(0.18)
Ghent 4	2.06	1.86	(0.20)	2.13	1.93	(0.19)	2.17	1.98	(0.19)	2.21	2.02	(0.19)
Mill Creek 1	0.87	0.94	0.08	0.89	0.97	0.08	0.91	0.98	0.07	0.93	1.01	0.08
Mill Creek 2	1.09	0.98	(0.11)	1.11	1.01	(0.10)	1.13	1.01	(0.12)	1.15	1.04	(0.11)
Mill Creek 3	1.32	1.33	0.01	1.35	1.38	0.03	1.38	1.40	0.02	1.41	1.45	0.04
Mill Creek 4	1.33	1.25	(0.09)	1.22	1.38	0.17	1.24	1.31	0.07	1.26	1.36	0.10
Trimble 1	1.25	1.63	0.38	1.28	1.69	0.42	1.30	1.74	0.44	1.32	1.79	0.47
Trimble 2	1.41	1.54	0.13	1.46	1.62	0.16	1.49	1.67	0.18	1.51	1.72	0.21

FGD O&M increases at Brown, Ghent, and Mill Creek in 2019 BP

FGD	2019			2020			2021			2022		
($/MWh)	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff
Brown 1	0.66	0.70	0.04	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Brown 2	0.61	0.65	0.04	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Brown 3	0.65	0.68	0.04	0.33	0.70	0.36	0.67	0.70	0.02	0.69	0.72	0.04
Ghent 1	0.40	0.52	0.12	0.41	0.53	0.12	0.42	0.54	0.13	0.42	0.56	0.13
Ghent 2	0.36	0.47	0.11	0.37	0.48	0.11	0.38	0.49	0.12	0.38	0.50	0.12
Ghent 3	0.42	0.54	0.12	0.43	0.56	0.13	0.43	0.57	0.14	0.44	0.58	0.14
Ghent 4	0.42	0.55	0.12	0.43	0.56	0.13	0.44	0.58	0.14	0.45	0.59	0.14
Mill Creek 1	0.37	0.52	0.15	0.39	0.54	0.15	0.39	0.55	0.16	0.40	0.56	0.15
Mill Creek 2	0.38	0.52	0.14	0.38	0.54	0.16	0.39	0.55	0.15	0.40	0.56	0.16
Mill Creek 3	0.40	0.54	0.14	0.41	0.56	0.15	0.42	0.57	0.15	0.43	0.58	0.15
Mill Creek 4	0.41	0.55	0.13	0.43	0.56	0.13	0.44	0.58	0.14	0.44	0.59	0.15
Trimble 1	0.48	0.46	(0.02)	0.49	0.49	0.01	0.50	0.51	0.01	0.50	0.52	0.02
Trimble 2	0.39	0.35	(0.04)	0.39	0.37	(0.03)	0.40	0.38	(0.02)	0.40	0.39	(0.02)

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SCR O&M decreases at all stations in 2019 BP

SCR ($/MWh)	2019			2020			2021			2022		
	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff
Brown 1	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Brown 2	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Brown 3	0.39	0.29	(0.09)	0.40	0.31	(0.09)	0.40	0.32	(0.09)	0.41	0.32	(0.09)
Ghent 1	0.34	0.28	(0.06)	0.35	0.30	(0.06)	0.36	0.30	(0.05)	0.36	0.31	(0.05)
Ghent 2	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Ghent 3	0.29	0.24	(0.05)	0.30	0.25	(0.05)	0.30	0.26	(0.05)	0.31	0.27	(0.04)
Ghent 4	0.34	0.28	(0.06)	0.35	0.30	(0.06)	0.36	0.30	(0.05)	0.36	0.31	(0.05)
Mill Creek 1	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Mill Creek 2	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Mill Creek 3	0.39	0.32	(0.07)	0.41	0.34	(0.06)	0.41	0.35	(0.06)	0.42	0.36	(0.06)
Mill Creek 4	0.39	0.30	(0.09)	0.38	0.34	(0.04)	0.39	0.33	(0.06)	0.39	0.34	(0.06)
Trimble 1	0.20	0.17	(0.03)	0.21	0.18	(0.03)	0.21	0.19	(0.03)	0.21	0.19	(0.02)
Trimble 2	0.17	0.15	(0.03)	0.18	0.15	(0.03)	0.18	0.16	(0.02)	0.19	0.16	(0.02)

SO_3 O&M lower at Ghent in 2019 BP

SO3 ($/MWh)	2019 2018 BP	2019 2019 BP	2019 Diff	2020 2018 BP	2020 2019 BP	2020 Diff	2021 2018 BP	2021 2019 BP	2021 Diff	2022 2018 BP	2022 2019 BP	2022 Diff
Brown 1	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Brown 2	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Brown 3	0.24	0.24	(0.00)	0.13	0.25	0.12	0.25	0.25	(0.00)	0.26	0.26	(0.00)
Ghent 1	0.75	0.75	0.00	0.78	0.79	0.00	0.80	0.80	0.00	0.82	0.82	0.00
Ghent 2	0.41	0.41	0.00	0.43	0.43	0.00	0.44	0.44	0.00	0.45	0.45	0.00
Ghent 3	0.74	0.74	0.00	0.77	0.78	0.00	0.79	0.79	0.00	0.81	0.81	0.00
Ghent 4	0.74	0.75	0.00	0.78	0.78	0.00	0.80	0.80	0.00	0.81	0.82	0.00
Mill Creek 1	0.21	0.18	(0.03)	0.21	0.19	(0.03)	0.22	0.18	(0.04)	0.22	0.19	(0.03)
Mill Creek 2	0.21	0.21	(0.00)	0.22	0.22	0.00	0.22	0.21	(0.01)	0.23	0.23	(0.00)
Mill Creek 3	0.36	0.26	(0.10)	0.37	0.27	(0.10)	0.38	0.25	(0.12)	0.38	0.28	(0.11)
Mill Creek 4	0.36	0.23	(0.13)	0.30	0.27	(0.03)	0.31	0.22	(0.08)	0.31	0.24	(0.07)
Trimble 1	0.57	0.58	0.01	0.58	0.59	0.01	0.59	0.60	0.01	0.60	0.61	0.01
Trimble 2	0.50	0.50	0.00	0.53	0.53	0.00	0.54	0.54	0.00	0.55	0.55	0.00

Mercury O&M increases at Trimble, but decreases at other stations in 2019 BP

Mercury ($/MWh)	2019			2020			2021			2022		
	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff
Brown 1	0.96	0.54	(0.41)	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Brown 2	0.87	0.46	(0.41)	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Brown 3	0.93	0.32	(0.61)	0.86	0.33	(0.53)	1.00	0.33	(0.66)	1.04	0.34	(0.69)
Ghent 1	0.55	0.29	(0.26)	0.56	0.29	(0.27)	0.57	0.30	(0.28)	0.58	0.30	(0.28)
Ghent 2	0.54	0.28	(0.26)	0.55	0.29	(0.27)	0.56	0.29	(0.27)	0.57	0.30	(0.28)
Ghent 3	0.54	0.28	(0.26)	0.55	0.29	(0.27)	0.57	0.29	(0.27)	0.58	0.30	(0.28)
Ghent 4	0.55	0.28	(0.26)	0.56	0.29	(0.27)	0.57	0.30	(0.28)	0.58	0.30	(0.28)
Mill Creek 1	0.29	0.24	(0.04)	0.29	0.25	(0.04)	0.30	0.25	(0.05)	0.30	0.26	(0.05)
Mill Creek 2	0.50	0.25	(0.25)	0.51	0.25	(0.26)	0.52	0.26	(0.26)	0.53	0.26	(0.27)
Mill Creek 3	0.17	0.21	0.04	0.17	0.22	0.05	0.17	0.22	0.05	0.18	0.23	0.06
Mill Creek 4	0.17	0.17	0.00	0.11	0.22	0.11	0.11	0.18	0.07	0.11	0.19	0.08
Trimble 1	0.00	0.41	0.41	0.00	0.43	0.43	0.00	0.45	0.45	0.00	0.47	0.47
Trimble 2	0.35	0.55	0.20	0.35	0.57	0.21	0.36	0.59	0.23	0.37	0.62	0.25

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Process-Water Systems O&M newly reflected in 2019 BP

PWS ($/MWh)	2019			2020			2021			2022		
	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff	2018 BP	2019 BP	Diff
Brown 1	0.00	0.00	0.00	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Brown 2	0.00	0.00	0.00	N/A	N/A	--	N/A	N/A	--	N/A	N/A	--
Brown 3	0.00	0.00	0.00	0.00	0.06	0.06	0.00	0.06	0.06	0.00	0.06	0.06
Ghent 1	0.00	0.09	0.09	0.00	0.10	0.10	0.00	0.10	0.10	0.00	0.11	0.11
Ghent 2	0.00	0.08	0.08	0.00	0.10	0.10	0.00	0.10	0.10	0.00	0.11	0.11
Ghent 3	0.00	0.09	0.09	0.00	0.10	0.10	0.00	0.10	0.10	0.00	0.11	0.11
Ghent 4	0.00	0.09	0.09	0.00	0.10	0.10	0.00	0.10	0.10	0.00	0.11	0.11
Mill Creek 1	0.00	0.10	0.10	0.00	0.10	0.10	0.00	0.11	0.11	0.00	0.11	0.11
Mill Creek 2	0.00	0.09	0.09	0.00	0.10	0.10	0.00	0.11	0.11	0.00	0.11	0.11
Mill Creek 3	0.00	0.09	0.09	0.00	0.10	0.10	0.00	0.11	0.11	0.00	0.11	0.11
Mill Creek 4	0.00	0.09	0.09	0.00	0.10	0.10	0.00	0.11	0.11	0.00	0.11	0.11
Trimble 1	0.00	0.09	0.09	0.00	0.12	0.12	0.00	0.13	0.13	0.00	0.13	0.13
Trimble 2	0.00	0.11	0.11	0.00	0.12	0.12	0.00	0.13	0.13	0.00	0.13	0.13

Maintenance schedule reflects acceleration of Brown 3 overhaul and deferral of Cane Run 7 outages

Maintenance-Weeks

	2019 BP					2018 BP					2019 BP - 2018 BP					
	2019	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2022**	**2023**	**2019**	**2020**	**2021**	**2022**	**2023**	**Totals**
Brown 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brown 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Brown 3	9	2	4	3	1	3	8	1	3	1	6	(6)	3	-	-	3
Ghent 1	3	4	8	6	3	3	4	8	4	3	-	-	-	2	-	2
Ghent 2	9	4	4	3	3	8	4	4	3	3	1	-	-	-	-	1
Ghent 3	4	3	3	3	4	4	3	3	3	4	-	-	-	-	-	-
Ghent 4	4	8	4	4	3	4	8	4	4	3	-	-	-	-	-	-
Mill Creek 1	8	2	4	2	4	8	1	4	1	4	-	1	-	1	-	2
Mill Creek 2	1	4	1	4	1	1	4	1	4	1	-	-	-	-	-	-
Mill Creek 3	9	1	4	1	4	9	1	4	1	4	-	-	-	-	-	-
Mill Creek 4	1	6	1	8	1	1	4	1	8	1	-	2	-	-	-	2
Trimble County 1	5	2	6	2	5	5	2	6	2	5	-	-	-	-	-	-
Trimble County 2	7	5	5	5	6	6	5	5	5	6	1	-	-	-	-	1
Cane Run 7	1	5	1	2	1	5	2	2	2	8	(4)	3	(1)	-	(7)	(9)
Totals	**61**	**46**	**45**	**43**	**36**	**57**	**46**	**43**	**40**	**43**	**4**	**-**	**2**	**3**	**(7)**	**2**
MW-Maint Wks*	**27,970**	**23,509**	**21,507**	**21,372**	**17,610**	**27,224**	**22,639**	**20,965**	**20,122**	**22,447**	**746**	**870**	**542**	**1,250**	**(4,837)**	**(1,430)**

*Coal + CR7 Only

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Modeled EFOR reflects adjustments derived from 10-year historical data

Unit	Modeled EFOR %		
	2019 BP	2018 BP	2019 BP - 2018 BP
Brown 1	5.7	5.7	0.0
Brown 2	5.7	5.7	0.0
Brown 3	5.7	5.7	0.0
Ghent 1	5.2	5.5	(0.3)
Ghent 2	5.2	5.5	(0.3)
Ghent 3	5.2	5.5	(0.3)
Ghent 4	5.2	5.5	(0.3)
Mill Creek 1	5.2	5.5	(0.3)
Mill Creek 2	5.2	5.5	(0.3)
Mill Creek 3	5.2	5.5	(0.3)
Mill Creek 4	5.2	5.5	(0.3)
Trimble County 1	5.2	5.5	(0.3)
Trimble County 2	9.3	7.6	1.7
Cane Run 7	3.0	3.0	0.0
Weighted Average EFOR	**5.4**	**5.4**	**(0.0)**

Heat rates reflect results of updated performance testing using granular PI data

	Summer Net Heat Rates at Max Load (Btu/kWh)			Winter Net Heat Rates at Max Load (Btu/kWh)			
	2018 BP	2019 BP	Percent Change	2018 BP	2019 BP	Percent Change	Average Heat Rate, 2017 KPIs
BR1	10,615	10,798	1.7%	10,523	10,705	1.7%	14,064
BR2	10,577	10,499	-0.7%	10,479	10,171	-2.9%	11,295
BR3	11,139	10,988	-1.4%	10,924	11,064	1.3%	11,745
GH1	10,686	10,799	1.1%	10,521	10,769	2.4%	10,892
GH2	10,039	10,043	0.0%	9,978	10,160	1.8%	10,541
GH3	11,012	11,071	0.5%	10,970	11,081	1.0%	11,295
GH4	10,804	10,821	0.2%	10,573	10,768	1.8%	10,846
MC1	10,423	10,513	0.9%	10,352	10,502	1.4%	10,503
MC2	10,664	10,802	1.3%	10,506	10,491	-0.1%	10,729
MC3	10,480	10,408	-0.7%	10,368	10,557	1.8%	10,669
MC4	10,407	10,352	-0.5%	10,218	10,284	0.6%	10,470
TC1	10,529	10,341	-1.8%	10,497	10,210	-2.7%	10,510
TC2	9,316	9,369	0.6%	9,106	9,194	1.0%	9,387
CR7	6,634	6,653	0.3%	6,718	6,624	-1.4%	6,562

Notes:

-Values shown represent net heat rates (in Btu/kWh).

-Summer and winter heat rates reflect values at maximum load. KPI heat rates reflect average observed values.

-Heat rate changes reflect calibration of forecasted fuel burn to actual fuel burn.

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2019 fuel cost comparison – annual averages

Fuel Expense ($/mmBtu)				Delta	
		2019 BP 2019	2018 BP 2019	2019 BP 2019 - 2018 BP 2019	% Change
COAL	BR	2.38	2.51	(0.13)	-5%
	GH	1.96	1.98	(0.03)	-1%
	MC	2.03	2.04	(0.01)	0%
	TC HS	1.97	1.99	(0.02)	-1%
	TC PRB	2.17	2.24	(0.07)	-3%
GAS	Gas BR	2.73	2.84	(0.11)	-4%
	Gas TC	2.73	2.84	(0.11)	-4%
	Gas CR7	2.73	2.84	(0.10)	-4%
	Gas PR	2.73	2.84	(0.11)	-4%
	Gas Haef	7.25	7.95	(0.69)	-9%
OIL	Oil	16.19	13.79	2.40	17%

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2020 fuel cost comparison – annual averages

Fuel Expense ($/mmBtu)				Delta	
		2019 BP 2020	2018 BP 2020	2019 BP 2020 - 2018 BP 2020	% Change
COAL	BR	2.52	2.54	(0.03)	-1%
	GH	1.95	1.98	(0.03)	-2%
	MC	2.04	2.01	0.03	2%
	TC HS	1.96	1.98	(0.02)	-1%
	TC PRB	2.22	2.31	(0.09)	-4%
GAS	Gas BR	2.77	2.90	(0.13)	-5%
	Gas TC	2.77	2.90	(0.13)	-5%
	Gas CR7	2.77	2.90	(0.13)	-5%
	Gas PR	2.77	2.90	(0.13)	-4%
	Gas Haef	7.29	8.01	(0.71)	-9%
OIL	Oil	16.74	17.01	(0.28)	-2%

2021 fuel cost comparison – annual averages

Fuel Expense ($/mmBtu)					Delta	
		2019 BP 2021	2018 BP 2021		2019 BP 2021 - 2018 BP 2021	% Change
COAL	BR	2.59	2.68		(0.09)	-3%
	GH	2.01	2.00		0.00	0%
	MC	2.06	2.04		0.02	1%
	TC HS	2.02	2.01		0.00	0%
	TC PRB	2.29	2.37		(0.07)	-3%
GAS	Gas BR	2.83	3.02		(0.19)	-6%
	Gas TC	2.83	3.02		(0.19)	-6%
	Gas CR7	2.83	3.02		(0.19)	-6%
	Gas PR	2.84	3.02		(0.18)	-6%
	Gas Haef	7.36	8.13		(0.77)	-9%
OIL	Oil	17.74	19.27		(1.52)	-8%

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Market electricity prices are generally higher in 2019, but lower in 2020 in 2019 BP

Market Price Comparison

Market Price	2019 BP			2018 BP			2019 BP - 2018 BP		
$/MWh	Peak	Off-Peak	Weekend	Peak	Off-Peak	Weekend	Peak	Off-Peak	Weekend
Jan-19	31.88	26.02	26.54	33.21	27.18	26.76	-1.34	-1.16	-0.22
Feb-19	28.22	23.89	25.01	32.18	27.40	27.45	-3.96	-3.51	-2.45
Mar-19	33.90	27.06	28.11	31.58	23.91	28.23	2.32	3.15	-0.13
Apr-19	31.01	23.16	27.51	28.52	20.82	25.25	2.49	2.34	2.26
May-19	29.25	18.94	27.17	26.95	16.97	25.74	2.30	1.97	1.43
Jun-19	31.14	17.54	28.25	29.66	15.77	26.86	1.48	1.76	1.39
Jul-19	35.03	19.73	32.92	35.52	17.93	30.95	-0.49	1.80	1.97
Aug-19	33.25	18.91	28.63	33.41	16.97	26.24	-0.15	1.94	2.39
Sep-19	31.01	18.07	27.43	27.44	15.85	24.21	3.58	2.22	3.21
Oct-19	30.48	20.83	25.58	27.24	18.39	21.64	3.24	2.45	3.94
Nov-19	28.92	21.76	23.51	26.48	19.47	21.35	2.44	2.29	2.16
Dec-19	31.01	23.84	27.37	29.63	21.63	25.70	1.38	2.21	1.67
Jan-20	31.01	25.32	25.82	35.38	29.39	29.95	-4.36	-4.07	-4.12
Feb-20	27.54	23.32	24.41	34.42	29.24	30.27	-6.89	-5.92	-5.86
Mar-20	33.23	27.06	28.18	32.67	25.37	29.22	0.55	1.69	-1.04
Apr-20	30.44	23.16	27.51	30.18	22.65	26.90	0.26	0.51	0.62
May-20	28.85	18.81	26.04	28.90	19.61	27.66	-0.05	-0.80	-1.61
Jun-20	31.14	17.58	29.93	32.65	19.10	29.38	-1.51	-1.53	0.55
Jul-20	35.21	19.61	33.77	39.23	21.66	33.71	-4.01	-2.05	0.06
Aug-20	33.35	18.95	28.05	36.80	20.73	29.64	-3.46	-1.79	-1.59
Sep-20	30.21	18.07	28.06	30.16	18.90	26.72	0.05	-0.84	1.33
Oct-20	29.62	20.65	25.00	29.97	21.06	24.37	-0.36	-0.41	0.64
Nov-20	28.60	21.48	23.21	29.22	22.36	24.64	-0.62	-0.88	-1.43
Dec-20	30.92	23.44	27.17	31.65	24.22	28.20	-0.73	-0.78	[illegible]

Case Nos. 2018-00294 and 2018-00295
Attachment to Filing Requirement
807 KAR 5:001 Sec. 16(7)(c)
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Sinclair

Peak load and energy comparison

Peak Delta (2019 BP - 2018 BP)

MW	2018	2019	2020	2021	2022
Jan	37	54	43	15	12
Feb	(132)	(109)	(169)	(145)	(152)
Mar	60	121	52	53	62
Apr	45	21	26	167	29
May	211	202	208	214	199
Jun	(247)	(246)	(240)	(204)	(288)
Jul	(52)	(54)	(42)	(79)	22
Aug	(18)	(14)	2	(10)	(10)
Sep	14	12	22	23	(2)
Oct	(84)	(88)	(84)	(83)	(162)
Nov	91	75	70	35	52
Dec	(169)	(176)	(172)	(177)	(227)
Peak	**(18)**	**(14)**	**2**	**(10)**	**(10)**

Energy Delta (2019 BP - 2018 BP)

GWh	2018	2019	2020	2021	2022
Jan	21	17	18	15	10
Feb	(78)	(65)	(78)	(81)	(84)
Mar	14	48	16	12	9
Apr	26	18	19	17	14
May	105	103	104	103	101
Jun	(136)	(137)	(133)	(134)	(135)
Jul	(28)	(30)	(24)	(24)	(24)
Aug	(37)	(37)	(31)	(31)	(32)
Sep	0	(0)	3	3	2
Oct	(13)	(15)	(13)	(14)	(15)
Nov	48	44	45	42	39
Dec	(97)	(104)	(101)	(104)	(108)
Total	**(174)**	**(159)**	**(176)**	**(197)**	**(222)**

Power Generation
LG&E and KU Utilities
2019 Operating Plan

August 2018

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Plan Highlights

- Major investment and integration of environmental compliance – Coal Combustion Residuals (CCR), pond closures and Process Water/Effluent water Limit Guidelines (ELG)
- Generation forecast assumes continued trend of high Natural Gas Combined Cycle (NGCC) production levels based on current projections for gas prices in first three years of the plan; NGCC production levels taper off later in the plan as gas prices increase
- Increased resource requirements to meet and maintain compliance with incremental regulatory requirements – begin staffing to operate Process Water plants in 2018
- Brown 1 and 2 to be retired March 1, 2019. Brown coal investment includes unit 3 only.

Major Operational Assumptions

- **No generation capacity additions are in the plan through 2023.**
- **Brown 1 and 2 to be retired March 1, 2019. Capital spend is based on a Unit 3 only generation profile beginning in spring 2018.**
- **The next turbine overhauls by unit are as follows:**
  - **2018: Ghent 3, Mill Creek 2, Trimble 2 (HP rotor and IP rotors)**
  - **2019: Brown 3, Ghent 2, Mill Creek 1, Mill Creek 3, Trimble 2 (both LP rotors)**
  - **2020: Trimble 2 (Generator), Ghent 4**
  - **2021: Ghent 1.**
  - **2022: Mill Creek 4.**
  - **2023: None**
- **Demolition Timing:**
  - **Paddy's Run Coal Plant was completed in 2017.**
  - **Cane Run Coal Plant is contracted for 2017-2019.**
  - **Green River planned for 2018-2019.**
  - **Pineville Station planned for 2018-2019.**
  - **Tyrone Station planned for 2018-2019.**
  - **Canal Station planned for 2020-2021.**

Major Financial Assumptions

- Amended 2016 ECR filed January 26, 2018 for smaller, modified Phase II of the Landfill and closure of the Main Ash Pond not covered by Landfill Phases I, modified II, and hardscaped areas.

- Planned outage normalization regulatory treatment began July 1, 2017
  - Budgeted in accordance with revenue requirements allowed in 2017 rate proceeding with difference recorded in a regulatory asset or liability
  - Assumes this treatment will continue in future regulatory proceedings relative to Kentucky jurisdiction
  - Assumes amortization of regulatory assets or liabilities will be over a eight year period
  - Base rate case will be filed in third quarter 2018 for test year beginning May 1, 2019 through April 30, 2020

- Labor budget built on current work force plan recommendations. Assumptions include anticipated employee retirements and wage increase for current employees on average of 3% per year.

- Supplemental contractor work force includes on average a 2.5% escalation in costs based on approved contracts.

- Total Operating Costs remain in line with the approved 2018 Business Plan with the exception of costs associated with landfill well monitoring and new process water systems beginning in 2019.

Major Assumptions – Process Water

- Process water facilities (Phys-chem for Mercury, Arsenic, metals) in-service 2019 for all four coal-fired plants:
  - Mill Creek - January 2019
  - Trimble County - April 2019
  - Ghent - June 2019
  - E.W. Brown - October 2019
- Labor resources consistent at each site
- All labor and non labor costs for operating and maintaining process water systems will be in base rates.
- Effluent water guideline (ELG) has placeholder spend primarily in 2021-2023 until final ELG regulations are promulgated, which are expected in 2019. Mill Creek has an anticipated in service date of November 2022 while Trimble County and Ghent anticipated in November 2023. ELG at E.W. Brown has been removed due to less volume resulting in cycling up chlorides and closed loop on WFGD.
- Plan assumes a proposed ECR filing in the first quarter of 2020 time frame seeking recovery of ELG costs, both capital and operating expense.

Major Assumptions – Combustion Turbines

- Combustion turbine (CT) outages in the plan:
  - Dollars are split between O&M and capital based on the estimated scope of work that is reconditioning (expense – approximately 5%) vs. new parts (capital – approximately 95%).
  - For the second set of Trimble CT hot gas path inspections, the schedule is one unit each in 2017, 2018, 2020, 2022 and 2023.
  - This order may change in conjunction with the majors and rotor inspections during this plan. Currently, the majors and rotor inspections are just outside of the 5-year planning window.
  - Funding for enhanced in line inspections for gas transmission included in plan for Trimble County (2019) and E.W. Brown (2021) – included in fuel costs.
  - Brown C inspections by unit are as follows:
    - Unit 11 in 2018.
    - Unit 6 in 2019.
    - Unit 7 in 2021.
    - Unit 8 in 2021.
    - Unit 9 in 2024.
    - Unit 10 in 2026.

- Brown 6 and 7 Long-Term Services Agreement (LTSA) is in place.

- The CT component outages for Cane Run 7 are a Hot Gas Path Inspection (HGPI) Spring 2020, Combustion Inspection March, 2022, and a major in 2024 (HGPI and turbine overhaul).
    - Cane Run 7 CT's are covered under a signed Long Term Program Contract (LTPC).

Major Assumptions- Coal Combustion Residuals (CCR's)

- EPA finalized the CCR rule on December 19, 2014 (published in the Federal Register on April 17, 2015).
  - Maintained the non-hazardous designation of CCRs.
  - Does not require the immediate closure of unlined CCR impoundments but instead lists several criteria that must be met to continue operation. Some of those criteria include:
    - Siting requirements (wetlands, karst, water table …)
    - Dam safety factors
    - Groundwater monitoring and statistical evaluation
    - Flood control system
  - Requires development of:
    - Emergency action plans
    - Fugitive dust control plan
    - Inspection programs
    - Public available internet site for placement of operating data
  - Current design of new landfill construction project at Trimble, as well as the landfills constructed at Ghent and E.W. Brown meet the requirements of the rule.
  - Expect CCR impoundments to stop receiving CCR no later than April 2019 due to trigger of groundwater criteria.
  - Congress passed and the President signed the Water Infrastructure Improvements for the Nation Act (WIIN Act) on December 16, 2016. The WIIN Act is the first step to allow for the implementation of the federal CCR Rule through a state or federal based permit program.
  - On November 15, 2017 the EPA issued the CCR Rule "Remand Rule". The Remand Rule establishes a timeframe for the EPA to reconsider various aspects of the CCR Rule that have been brought forth by the utility industry and environmentalist. As of June, the Remand Rule does not appears to affect the direction or timing of the Companies compliance program.
  - All CCR impoundment closures included in approved 2016 ECR filing.

Major Assumptions – CCR (continued)

- **CCR Impoundment Closures under the CCR Rule by year are as follows:**

  - **2018: Mill Creek Clearwell and Construction Runoff Ponds; Ghent Reclaim Pond and Gypsum Stack Phase I of II. Mill Creek Emergency Pond was closed in 2017.**

  - **2019: Green River Main Ash Pond, ATB2 and SO2 Pond; Pineville Ash Pond; Tyrone Ash Pond; Mill Creek Dead Storage Pond; Brown Main Ash Pond (landfill Phase II (partial) and entire Phase III).**

  - **2020: Ghent Gypsum Stack Phase II of II; and Brown Aux Pond.**

  - **2021: Mill Creek Ash Pond.**

  - **2023: Ghent ATB#1, ATB #2, and Secondary Pond; Trimble County BAP and GSP. (2023 is the initial 5-year window, based on current negotiations related to off-site beneficial use, the GH and TC projects could be extended 1-2 years as a result of available CCR to close the facilities.)**

  - **In the year that each pond is closed, it will also be retired from the property accounting ARO perspective.**

  - **Monitoring wells and monitoring are added for all CCR impoundments and landfills affected by the CCR Rule. Well installation and monitoring until closure trigger (anticipated Oct. 2018) are capex against the ECR projects managed by PE. Monitoring cost post-trigger for 30-year minimum is covered by Generation Services projects. Monitoring costs for landfill wells are O&M and included in Generation Services budget**

LG&E KU
PPL companies

Major Assumptions – CCR (continued)

- Trimble County Landfill and Transport.
  - The contracted in-service month for the treatment system is August, 2018.
  - The contracted in-service month for the transport system is October, 2019.
  - The contracted in-service date for Landfill Phase 1A is Q4, 2019.
    - The KY-DWM landfill permit was issued in February, 2017.
    - The USACE 404 Permit was issued in June, 2017.
    - All permits required to allow landfill construction have been received.
    - While no lawsuits exist as of June 2018, litigation of permit remains possible; however, construction will continue as planned unless court issues a stay of the permit.

- A new Mill Creek landfill was removed from the planning period. The contract for a new gypsum dewatering facility was executed in 2017 with a contract in-service date by December 31, 2018 to support increased off-site beneficial reuse marketing of gypsum.

- All CCR Capital Projects' cost are based on actual awarded contract values or use nominal dollars, thus no longer using an annual escalation rate of 4.0% as in past BPs.

- The CCR impoundment closure projects assume that existing CCR materials from each plant can be beneficially used to construct the designed contour in each pond similar to that done at Cane Run. If that is not allowed by rule, the estimated cost of having to instead procure off-site fill material is an additional $180-200M.

2017-2023 Annual O&M Expenses
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Expenses Only:							
Non Outage Labor	$ 79,686	$ 81,669	$ 83,806	$ 87,197	$ 89,053	$ 91,226	$ 93,938
Non Outage Supplemental Contractors	20,265	20,340	24,177	25,619	26,381	27,110	27,963
Non Outage Plant Maintenance	50,084	53,762	53,690	53,385	55,388	54,202	54,156
Non Outage Plant Operations	18,384	17,391	18,023	17,652	17,381	17,591	17,618
Subtotal Non outage	$ 168,419	$ 173,162	$ 179,697	$ 183,852	$ 188,203	$ 190,128	$ 193,675
Outage	29,883	37,671	39,166	40,981	40,844	47,634	38,426
Total O&M Expense - Mgmt. View	**$ 198,302**	**$ 210,833**	**$ 218,862**	**$ 224,834**	**$ 229,047**	**$ 237,762**	**$ 232,101**
Plus:							
Base Gross Margin Items	$ 17,552	$ 16,349	$ 18,636	$ 21,007	$ 22,599	$ 25,231	$ 26,202
Mechanism Gross Margin Items	35,811	30,231	26,815	29,672	29,203	29,356	32,045
Total O&M Expense-GAAP View	**$ 251,665**	**$ 257,413**	**$ 264,313**	**$ 275,514**	**$ 280,849**	**$ 292,349**	**$ 290,347**

2017-2023 Annual O&M Expenses
Outages ($000)

Outages	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
LG&E Outage							
Coal Fired Units	$ 13,502	13,434	14,529	14,861	15,758	15,790	16,720
Combustion Turbines	369	688	608	1,113	1,080	1,603	1,131
Total LG&E Outage	$ 13,871	$ 14,122	$ 15,137	$ 15,974	$ 16,838	$ 17,393	$ 17,851
KU Outage							
Coal Fired Units	$ 14,249	21,561	22,702	21,852	20,973	25,412	17,753
Combustion Turbines	1,764	1,988	1,326	3,155	3,033	4,829	2,822
Total KU Outage	$ 16,013	$ 23,549	$ 24,028	$ 25,007	$ 24,007	$ 30,241	$ 20,575
Combined Outage							
Coal Fired Units	$ 27,751	$ 34,995	$ 37,231	$ 36,713	$ 36,731	$ 41,202	$ 34,474
Combustion Turbines	2,133	2,676	1,934	4,269	4,113	6,432	3,952
Total Combined Outage	$ 29,883	$ 37,671	$ 39,166	$ 40,981	$ 40,844	$ 47,634	$ 38,426

2017-2023 Annual O&M Expenses
Non Labor - Supplemental Contractors ($000)

Supplemental Contractors	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Fuel and Ash Handling Equipment	$ 5,963	$ 5,884	$ 6,083	$ 6,403	$ 6,785	$ 7,052	$ 7,308
Buildings and Grounds	4,987	5,062	5,421	5,554	5,571	5,711	5,873
Boiler Systems	2,751	3,880	4,785	4,638	4,697	4,832	4,953
Process Water	-	-	1,792	2,709	2,781	2,856	2,932
Plant Operations	2,700	2,525	3,410	4,280	4,410	4,527	4,664
Environmental	2,221	2,191	1,721	1,869	1,908	1,908	1,981
Cooling Water Systems	521	522	474	498	511	514	534
Turbine/Generator Systems	391	297	172	177	179	185	186
Other	2,444	1,561	2,076	1,308	1,513	1,665	1,721
Total Supplemental Contractors (100%)	$ 21,978	$ 21,920	$ 25,934	$ 27,436	$ 28,356	$ 29,249	$ 30,152
Trimble County Partner	$ (1,713)	$ (1,580)	$ (1,757)	$ (1,817)	$ (1,975)	$ (2,139)	$ (2,189)
Total Supplemental Contractors net	$ 20,265	$ 20,340	$ 24,177	$ 25,619	$ 26,381	$ 27,110	$ 27,963

2017-2023 Annual O&M Expenses
Non Labor - Maintenance ($000)

Maintenance	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Boiler Systems	$ 9,756	$ 11,509	$ 11,984	$ 12,256	$ 11,790	$ 12,385	$ 12,026
Turbine/Generator Systems	3,848	3,787	5,368	5,014	5,405	4,918	5,114
Cooling Water Systems	3,602	4,956	4,328	4,550	4,094	4,347	4,618
Fuel and Ash Handling Equipment	7,814	8,376	7,321	7,893	7,679	8,191	8,377
Buildings and Grounds	6,693	7,817	5,982	5,507	5,777	5,788	5,583
Flue Gas Desulfurization (FGD)	3,083	3,147	2,893	3,202	3,391	3,453	3,354
Limestone Systems	3,252	2,648	2,998	2,533	3,272	2,645	3,183
Tools and Consumables	2,192	2,536	1,970	1,968	1,969	1,969	1,969
Process Water	-	-	1,343	2,085	2,141	2,197	2,253
Compressed Air Systems	998	1,031	1,085	1,107	1,300	1,105	931
Computer/control Systems	1,862	2,224	2,230	2,298	2,334	2,362	2,388
Obsolete Inventory	995	824	3,282	1,242	1,603	1,187	739
Selective Catalytic Reduction (SCR) systems	616	895	754	879	814	904	859
Green River and Brown Regulatory Assets	817	446	(1,416)	670	670	223	-
Other Maintenance	7,218	6,104	6,161	4,791	6,338	6,428	6,688
Total Maintenance (100%)	$ 52,746	$ 56,301	$ 56,284	$ 55,994	$ 58,578	$ 58,101	$ 58,083
Trimble County Partner	$ (2,662)	$ (2,539)	$ (2,593)	$ (2,610)	$ (3,190)	$ (3,899)	$ (3,927)
Total Maintenance net	$ 50,084	$ 53,762	$ 53,690	$ 53,385	$ 55,388	$ 54,202	$ 54,156

2017-2023 Annual O&M Expenses
Non Labor - Operations ($000)

Operations	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Chemicals/Diesel	$ 3,822	$ 3,798	$ 4,840	$ 4,744	$ 4,519	$ 4,515	$ 4,523
Administrative and General Supplies	3,141	1,967	1,976	1,987	2,016	2,043	2,062
Health and Safety	1,654	1,669	1,782	1,805	1,790	1,820	1,806
Fuel Handling Equipment	1,328	1,839	1,736	1,794	1,813	1,847	1,860
Tools and Consumables	830	744	1,054	1,060	1,073	1,087	1,097
Water and Water Treatment	682	942	888	919	931	944	955
HydroElectric facilities	912	898	964	978	993	1,008	1,023
Combustion Turbine facilities	609	858	1,051	1,120	1,190	1,247	1,268
Environmental	1,369	1,000	338	292	408	527	512
Training and Development	175	292	460	463	466	469	472
Green River Regulatory Asset	1,766	963	321	-	-	-	-
Other Operations	2,830	2,992	3,264	3,169	2,911	2,869	2,887
Total Operations (100%)	$ 19,118	$ 17,962	$ 18,674	$ 18,331	$ 18,111	$ 18,376	$ 18,464
Trimble County Partner	$ (734)	$ (572)	$ (651)	$ (679)	$ (730)	$ (785)	$ (847)
Total Operations net	$ 18,384	$ 17,391	$ 18,023	$ 17,652	$ 17,381	$ 17,591	$ 17,618

2017-2023 Annual Expenses
Base Gross Margin Items ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Supplemental Contractors	$ 361	$ 323	$ 330	$ 288	$ 300	$ 312	$ 324
Refined Coal	(1,377)	(2,833)	(3,037)	(3,102)	(1,934)	-	-
Activated Carbon	36	34	19	-	(0)	0	0
Process Water Chemicals	-	-	1,833	2,859	2,917	3,017	3,145
Liquid Injection - Reagent Only	1,389	1,437	1,435	1,511	1,543	1,611	1,627
Other Waste Disposal	(75)	(250)	(33)	630	657	675	695
NOx Reduction Reagent	4,873	4,994	4,271	4,459	4,509	4,649	4,971
Scrubber Reactant Ex	10,740	11,373	12,569	12,994	13,240	13,569	14,039
Sorbent Injection Operation	-	-	-	-	-	-	-
Sorbent Reactant - Reagent Only	1,605	1,271	1,250	1,368	1,367	1,398	1,400
SO2 Emission Allowances	-	-	-	-	-	-	-
Total Base Gross Margin	$ 17,552	$ 16,349	$ 18,636	$ 21,007	$ 22,599	$ 25,231	$ 26,202

2017-2023 Annual Expenses
Mechanism Gross Margin Items ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Labor	$ 1,976	$ 1,894	$ 2,900	$ 3,428	$ 3,106	$ 2,716	$ 3,117
Supplemental Contractors	5,175	4,911	4,938	5,250	5,358	5,492	5,859
ECR ELG	-	-	-	-	-	100	1,248
ECR Maintenance Of SCR/NOx Reduction Equip	144	202	107	109	111	113	114
ECR Baghouse Maintenance	492	545	727	912	960	964	1,046
ECR Fly Ash Disposal	324	(2,552)	(4,186)	(4,179)	(4,172)	(4,167)	(4,162)
ECR Activated Carbon	5,538	3,596	3,946	4,046	4,014	4,120	4,298
ECR Liquid Injection - Reagent Only	2,679	1,738	1,658	1,828	1,809	1,947	2,018
ECR Landfill Operations	2,390	2,346	1,930	1,930	1,933	1,936	1,938
ECR Landfill Maintenance	2,802	3,726	4,388	6,148	6,223	6,074	6,184
ECR CCP System Maintenance	101	149	215	221	228	232	237
ECR Maintenance-FGDs	784	938	866	876	836	556	401
ECR Nox Reduction Reagent	291	318	203	216	233	239	237
ECR Other Waste Disposal - Beneficial Reuse	561	437	(1,135)	(1,800)	(1,800)	(1,800)	(1,800)
ECR Sorbent Injection Maintenance	265	360	289	290	281	269	269
ECR Sorbent Injection Operation	66	242	96	100	102	104	106
ECR SO2 Emission Allowances	4	6	5	5	5	5	5
ECR Sorbent Reactant - Reagent Only	12,219	11,373	9,868	10,292	9,976	10,457	10,930
Total Mechanism Gross Margin	$ 35,811	$ 30,231	$ 26,815	$ 29,672	$ 29,203	$ 29,356	$ 32,045

O&M Annual Expense Reconciliation
($000)

	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
2018 Plan/Expectation	$ 215,020	$ 219,538	$ 227,030	$ 229,517	$ 231,448
Drivers:					
Process Water	$ 3,173	$ 4,993	$ 5,125	$ 5,260	$ 5,397
Landfill Well monitoring	313	362	101	101	101
Move BR3 outage 2020 into 2019	468	(468)			
Timing on CR7 outages	(316)	502	(2,624)	2,374	(5,469)
Other Outage expense	861	(50)	52	596	331
Other Maintenance	(657)	(44)	(638)	(85)	293
Current Plan - Mgt. View	$ 218,862	$ 224,834	$ 229,047	$ 237,762	$ 232,101

2017-2023 Capital Expenditures ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Brown CT Combustion Inspections	$ 8,167	$ 6,230	$ 20,892	$ 1,897	$ 32,179	$ -	3,048
Trimble CT Combustion Inspections	4,086	3,734	818	4,271	5,384	1,426	-
Cane Run 7 Hot Gas Path and Combustion Inspection	8,254	-	-	22,701	-	9,400	-
Cane Run 7 Blade replacments	3,601	67	-	-	-	-	-
BlackStart (Cane Run and Trimble County)	8,877	-	-	-	-	-	-
Ghent 3 Burner replacement	4,415	2,626	164	-	-	-	-
TC1 Gas Conversion	3,658	442	-	-	-	-	-
TC2 Gas Conversion	2,530	-	-	-	-	-	-
TC2 Water Wall replacement	2,349	3,537	-	-	-	-	-
Ghent Barge Unloader	2,415	6,324	-	-	-	-	-
Ghent 2 4Kv Switchgear	1,601	2,346	3,447	-	-	-	-
Ghent Cooling Tower Rebuilds	1,059	9,816	2,491	10,100	-	-	-
Mill Creek Cooling Towers	-	-	743	-	1,654	3,159	712
Brown CT Gas Pipeline Relocation	284	4,599	15,948	-	-	-	-
Ghent 1 Burner Corner Tubing	-	-	-	226	1,467	4,032	-
Ghent Stacker Reclaimer	-	3,462	5,761	-	-	-	-
Ghent 1 horizontal LTSH tubing	-	-	1,241	3,783	-	-	-
Ghent 1 Reheater Pendent Assembly Replacement	-	459	4,176	4,556	-	-	-
Ghent 1 Superheater Platen Pendents	-	287	1,524	2,797	-	-	-
Ohio Falls DCS upgrade	-	-	-	-	3,276	-	-
Mill Creek Stacker Reclaimer	-	-	-	1,289	8,180	-	-
Dix Dam Parapet Wall	-	-	100	5,505	-	-	-
Trimble County CT spare rotor	-	-	-	-	-	2,986	15,652
ECR recoverable	3,838	2,130	9,462	8,070	4,838	-	-
Outage related capital	38,026	56,444	98,259	62,059	89,179	66,120	85,773
Reliability related capital	57,750	45,661	59,826	22,364	36,560	19,631	25,217
Total Capital	$ 150,909	$ 148,166	$ 224,852	$ 149,618	$ 182,716	$ 106,754	$ 130,403
2018 Plan		$ 146,531	$ 208,536	$ 133,148	$ 203,305	$ 76,846	$ 190,802
Change		$ 1,635	$ 16,317	$ 16,470	$ (20,589)	$ 29,908	$ (60,400)

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Labor Expense ($000)

Salary Plan	2019 [1] Average Headcount	Base Salary	Overtime and all Other Labor	TIA Labor Expense	Total Salary & TIA Labor	2019 [2] Labor Expense	2020 Labor Expense	2021 Labor Expense	2022 Labor Expense	2023 Labor Expense
Exempt	303	$ 36,223	$ -	$ 2,764	$ 38,987					
Non-Exempt	84	7,483	881	666	9,030					
Union/Hourly	512	42,196	9,090	3,645	54,931					
Subtotal	899	$ 85,903	$ 9,971	$ 7,075	$ 102,949					
Co-ops / Interns	35	$ 1,153	$ -	$ -	$ 1,153					
Total	934	$ 87,056	$ 9,971	$ 7,075	$ 104,102	$ 87,120	$ 89,994	$ 91,650	$ 93,734	$ 96,018

[1] 100% Trimble County
[2] 75% Trimble County

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Employee Headcount by Work Group

Work Group or Major Dept.	June 30, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
Mill Creek	205	218	218	218	218	221	221
Trimble County/CTs	165	170	183	184	184	184	187
Cane Run/Ohio Falls	50	52	51	51	51	51	51
Ghent	218	219	216	216	216	216	219
Brown/Dix	126	126	128	126	123	121	119
Commercial Operations	45	44	44	44	44	44	44
Generation Services	47	53	53	55	55	55	55
Other Generation Support	16	14	14	14	14	13	13
Co-Ops/Interns	30	28	35	35	35	35	35
Total	902	924	942	943	940	940	944

- 2019 – 3 CCR maintenance positions Trimble; 10 operations positions Trimble; additional interns at Cane Run and Ghent
- 2020-2021 – 2 Mechanics at Trimble in 2020; offset by captured attrition (2020-2021)
- 2022 – 3 ELG positions at Mill Creek offset by captured attrition
- 2023 – 6 ELG positions at Ghent and Trimble partially offset by captured attrition

Supplemental Contractors by Work Group

Work Group or Type of Work	June 30, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
Mill Creek	123	125	125	125	125	126	126
Trimble County/CTs	85	85	92	90	90	90	90
Cane Run/Ohio Falls	7	7	7	6	6	6	6
Ghent	134	134	135	135	135	135	135
Brown/Dix	53	53	37	37	38	38	39
Commercial Operations	15	15	15	15	15	15	15
Generation Services	5	4	4	4	4	4	4
Central Service Shop	15	15	15	15	15	15	15
Process Water/ELG			25	25	25	25	29
Total	437	438	455	452	453	454	459

- Brown 1 and 2 employees displacing contractors in 2019 when units retire
- TC landfill contractors added in 2019
- Process Water contractors added in 2019 – 8 each at Mill Creek, Ghent and Trimble Co; 1 at Brown

2017-2023 Headcount Totals & Changes

	Year-End						
	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Employees							
TOTAL From (Page 21)	**917**	**924**	**942**	**943**	**940**	**940**	**944**
Prior Plan		921	953	951	947	941	
Change From Prior Plan		3	(11)	(8)	(7)	(1)	
Supplemental Contractors (Page 22)		438	455	452	453	454	459
Prior Plan		436	423	421	421	421	
Change from Prior Plan		2	32	31	32	33	
Total Workforce (Employees Plus Supplemental Contractors)							
Current Plan		1,362	1,397	1,395	1,393	1,394	1,403
Prior Plan		1,357	1,376	1,372	1,368	1,362	
Variance		5	21	23	25	32	

Plan Risks

- Personnel resources and knowledge transfer due to work force turnover as result of retirements
- Increased cost pressures due to inflation and commodity price increases
- Cane Run 7 operation and maintenance costs – warranty recently expired
- Any subsequent changes to approved or proposed environmental regulations will impact the investment, construction and implementation of new systems and resources needed in this plan
- Generation dispatch for the plan years is based on current view of regulations and assumptions on pricing for gas supply and allowances which is subject to significant changes to unit cost profiles and maintenance schedules if changes occur
- Integration of additional CCR equipment, pond closures and dry landfill conversions will be on an aggressive schedule with potential to impact outage schedules and forecasted operating expenses.

Operational Performance

Key Performance Indicators

KPI	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Generation (Twh)[1]	32.4	33.8	32.5	32.1	32.2	32.2	32.5
EAF (Steam)	84.8%	82.7%	79.5%	85.2%	85.7%	85.8%	87.0%
EFOR (Steam)	3.5%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Controllable Cost ($M)[2]	$250.4	$257.4	$264.3	$275.5	$280.8	$292.3	$290.3
Controllable Cost (per Mwh)[2]	$7.74	$7.62	$8.12	$8.58	$8.73	$9.07	$8.94
Cash Cost (per Mwh)[3]	$12.40	$12.00	$15.03	$13.24	$14.41	$12.38	$12.95
Cost Per Mwh [4]	$7.76	$7.91	$8.04	$8.19	$8.49	$8.81	$9.10
Recordable Injuries [5]	1.23	3.14	1.80	1.73	1.66	1.55	1.47
Days Away/Restricted/Transferred Case Rate (DART) [5]	0.61	0.67	0.72	0.67	0.63	0.63	0.59

[1] Steam Generation includes 75% of Trimble County 1 and 2.

[2] Controllable Costs include Utility O&M and Other Cost of Sales.

[3] Cash cost includes controllable costs plus capital divided by MWH (75% TC)

[4] Five year average - measure is non fuel O&M used in FERC benchmarking and includes all lines of business divided by MWH (75% TC)

[5] The 2018 number represents the June YTD value; Recordable injury rate without hearing loss is 1.12 YTD June

*2018 Forecast is from the 6&6 forecast.

Electric Distribution
LG&E and KU Utilities
2019 Operating Plan

September 2018 – Updated to reflect KPSC AMS ruling

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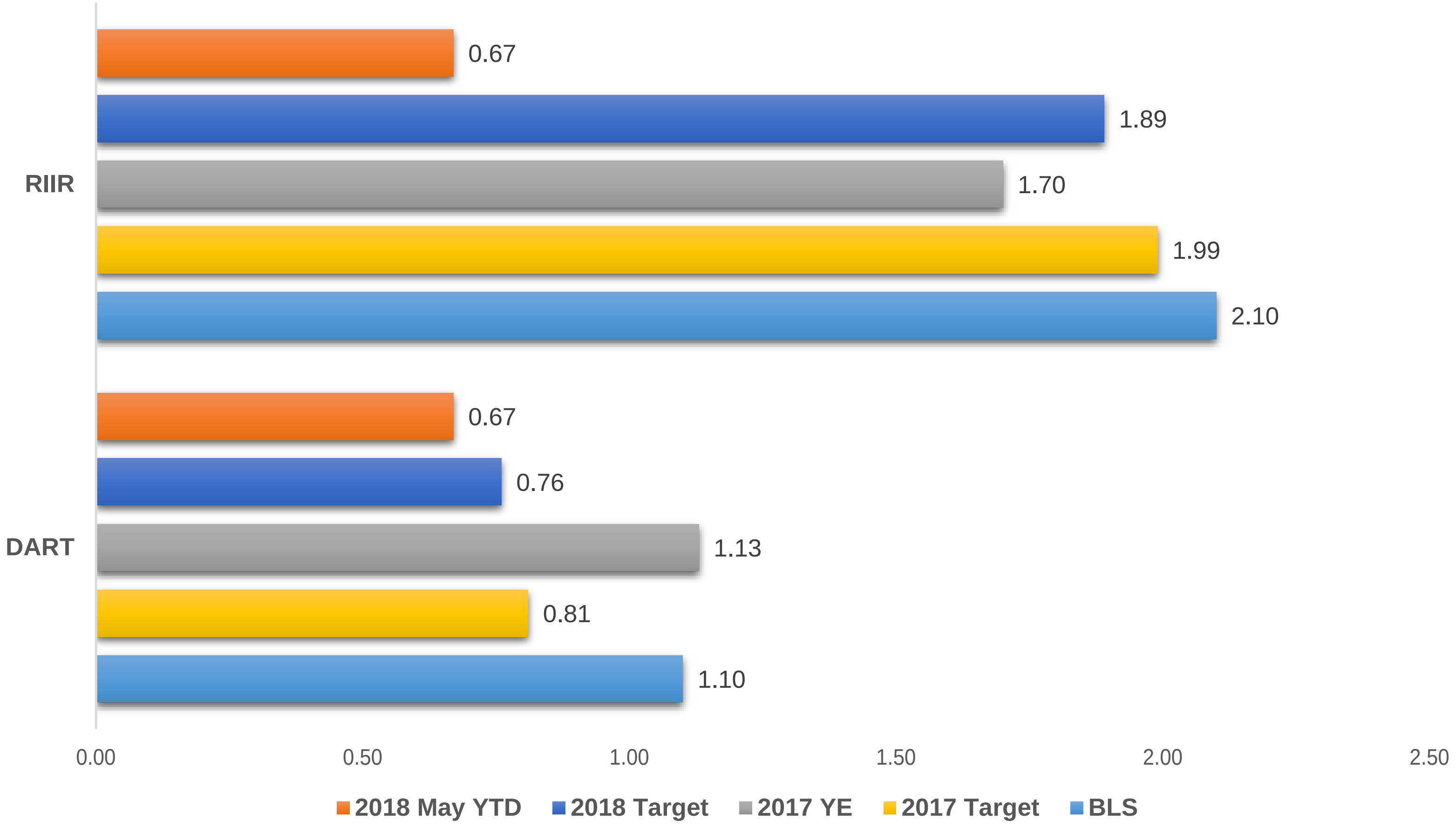
Plan Highlights

Electric Distribution's Business Plan provides for continued emphasis on the Company's core values of safety and customer satisfaction. Plan funding will continue to provide for safe, reliable, resilient and low cost electric service for customers, with priority given to the following:

- Employee, business partner and public safety
- Transfer of knowledge to new employees as retirements accelerate
- System enhancements to meet existing and future customer loads
- Electric system automation, hardening and protection to improve service reliability and system resiliency
- Technology advancements to enhance business processes, improve operational efficiencies and enhance communications with customers
- Asset replacements to address aging infrastructure
- Construction projects to serve new customers and satisfy customer requested projects
- Maintenance, inspections and operations programs which assure regulatory compliance and operational performance

Plan Highlights

Safety Performance - Electric

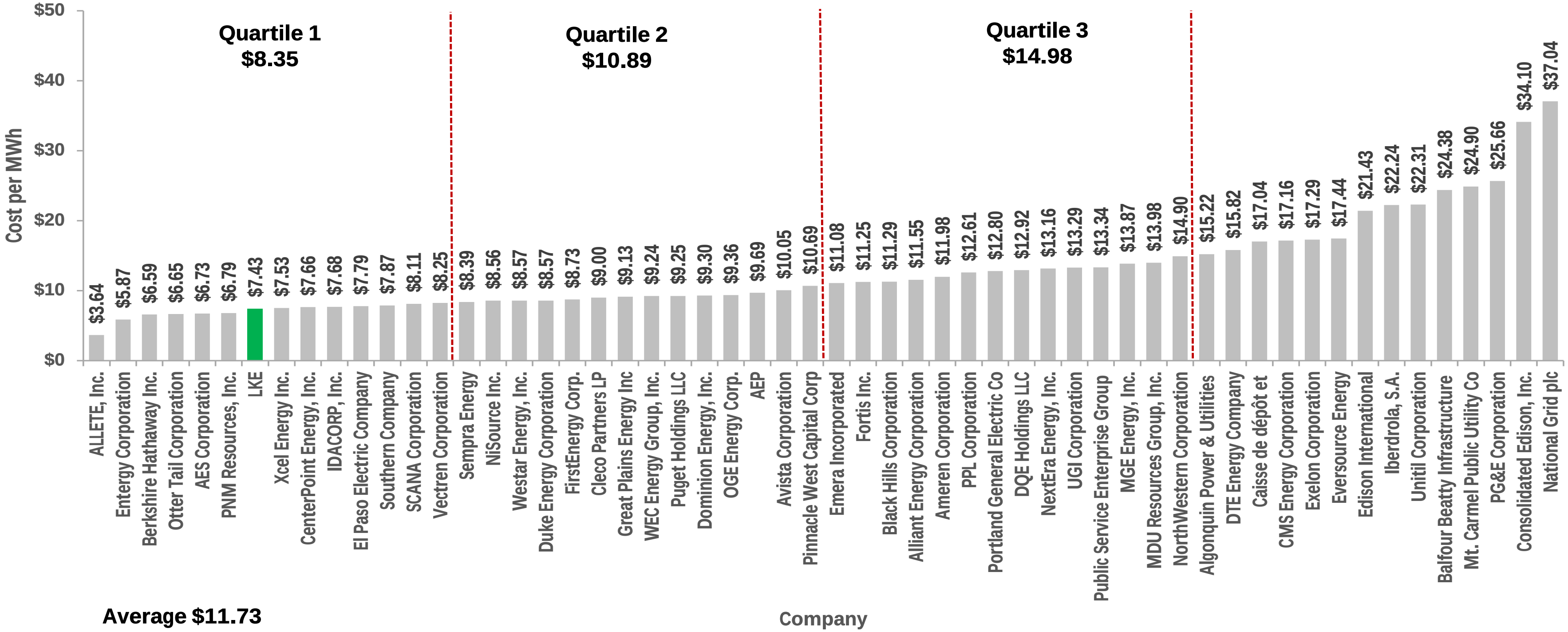


2016 BLS – most recent data

Plan Highlights

Total Electric Distribution Cash Cost per MWh

Overall Electric Distribution Expenditures per MWh
FERC Utility Cost Benchmarking – 5 Year Average Data (2013-2017)
(Electric Only)



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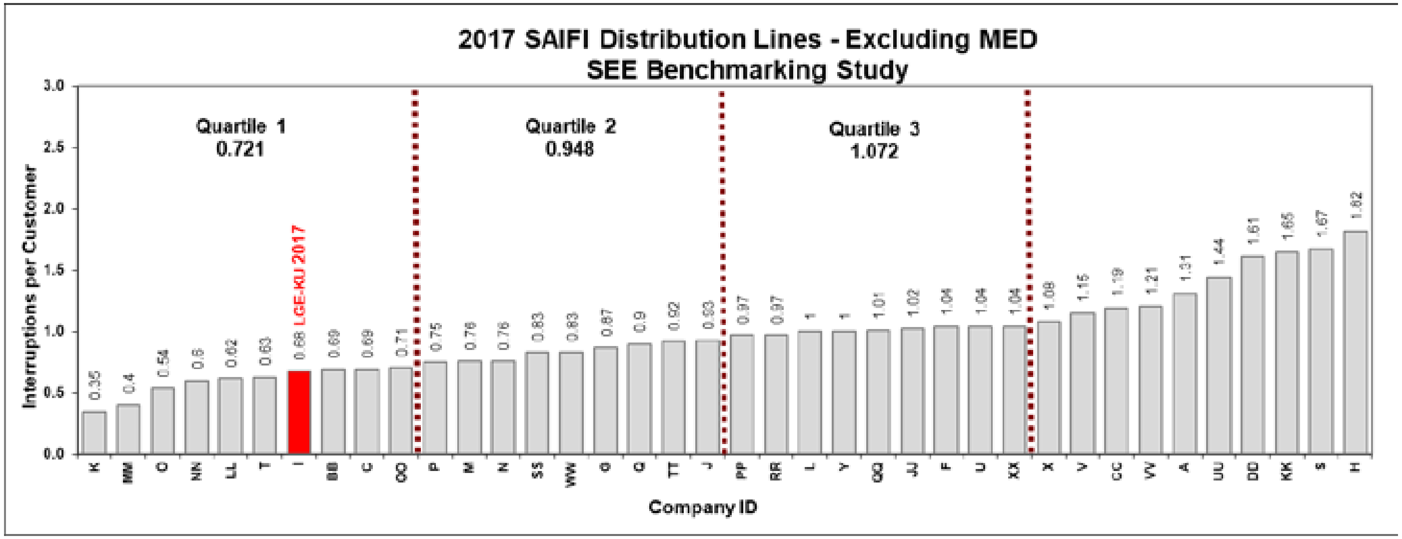
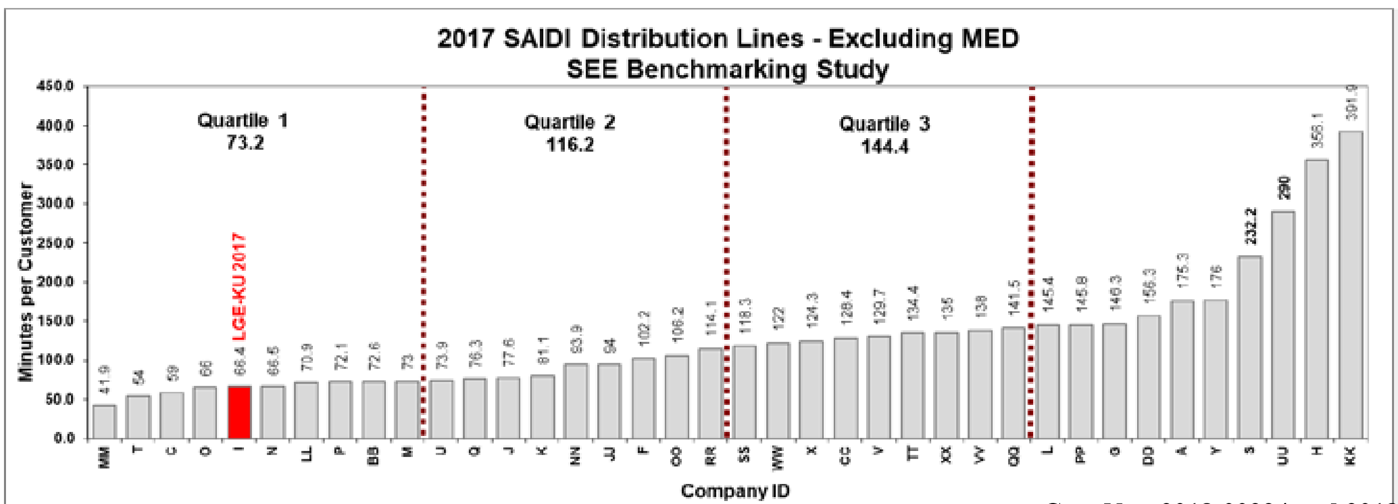
Plan Highlights

Reliability Performance





Plan Highlights

- Safety and Wellness
  - Continue commitment to employees, business partners and public safety
  - Focus on incident prevention plans and critical danger zones
  - Support transfer of safety knowledge from seasoned to new employees
  - Ensure a comprehensive safety/technical training plan is in place for all employees
  - Benchmark and implement industry best practices
  - Maintain industry leading performance
  - Continue to improve motor vehicle safety
  - Promote wellness initiatives as an aspect of safety

Plan Highlights

- Customer Experience
  - Respond effectively and efficiently to customer requests for service
  - Invest in system reliability and contingency to meet increasing customer expectations respective to service availability
  - Invest in aging infrastructure to continue long term service reliability
  - Advance grid intelligence to meet evolving customer expectations and align with industry trends
  - Respond to outage events in an efficient and effective manner, and continue to improve on the accuracy, timeliness, and provision of estimated restoration times
  - Build on technology which enhances business processes, reduces cycle times, and expands communications with customers
  - Focus on portraying a professional and positive image to customers
  - Satisfy system capacity needs to meet customer load

Major Assumptions

- Customer reliance on electricity continues to increase, with advancement of end use technologies and electrification of nearly everything. Accordingly, customer expectations respective to electric service safety, reliability, and quality continue to evolve.
- Expectations for system resiliency and outage responsiveness will continue to grow in the face of increased grid vulnerabilities linked to severe and extreme weather, threats of cyber and physical attacks, and interference from wildlife and vegetation.
- Cost pressures will continue to increase with decreasing load projections, and with continued investments needed for grid reliability and resiliency improvements, aging infrastructure replacement, and system enhancements to meet new load or load shifts associated with population movement from rural to urban service areas.
- Regulations governing the operation, maintenance, inspection, and construction of the electric distribution system will remain relatively steady.

Major Assumptions

- Across the industry, customers, regulators, and community leaders will continue to push for modernization of the electric grid, effective interconnection of distributed energy resources, increased operational flexibility, and enhanced customer communications.
- Customer interconnection of distributed generation and electric vehicles will increase slightly through the business plan period, as related costs continue to decline and efficiencies improve.
- Increased retirements and advancing technology will necessitate creative and timely solutions for converging legacy and future skillset needs, and transferring critical technical knowledge.
- New business growth will continue to increase moderately in urban service areas, and remain flat or decrease in most rural areas of the distribution system.

Major Assumptions

- New business funding levels will be based on known projects, customer growth forecasts and historical work activity.
  - Funding for known major customer investment projects will be budgeted separately.
  - LG&E and KU capital blankets will be escalated at 5% and 3% through the planning period.
- Reliability funding levels will continue to target regulatory compliance and step improvements in performance.
  - Allocated vegetation management expenses will continue to assure maintenance of a required 5-year trim cycle, and support hazard tree removal and emerald ash borer mitigation.
  - Phase I investments in distribution automation deployment will continue through 2021, and target 50% of customers and 20% of distribution circuits. Phase II of distribution automation is planned in 2022 and 2023, and will target an additional 20% of customers and 20% of distribution circuits.
  - Investments for targeted circuit hardening and reliability improvement projects will continue to be allocated based on circuit reliability performance and specific customer interruption frequencies.
  - Substation investments will provide for enhanced wildlife protection and expansion of Supervisory Control and Data Acquisition (SCADA).

Major Assumptions

- Distribution equipment replacement and repair investment and expense blankets will be budgeted based on historical trends.

- Infrastructure investments throughout the plan period will support continued improvements in system resiliency:
  — Distribution Substation Transformer Contingency Program
  — Pole Inspection, Treatment, and Replacement Program

- Aging infrastructure investments will place emphasis on:
  — Replacement of legacy substation equipment such as oil breakers, electro-mechanical relays, and underground exit cables.
  — Replacement of Paper Insulated Lead Covered (PILC) cable in the Downtown Louisville Distribution Network
  — Structural repair of vaults and manholes in the Downtown Louisville Distribution Network

- Weather related system repairs and service restoration budgets are based on historical trends (three year average).

2017-2023 Annual O&M Expenses
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Expenses Only:							
Labor	23,780	26,426	25,433	26,577	27,019	28,378	29,170
Non Labor							
Line Clearance [1]	20,829	23,736	24,693	24,535	25,578	25,477	25,966
Storm Restoration [2]	3,043	12,840	4,659	4,626	4,999	4,752	4,899
Outside Services - Supplemental	6,067	7,798	9,896	10,142	10,508	10,908	11,264
Outside Services - Other	2,736	1,863	1,252	1,054	791	753	826
Sub-Total Outside Services	8,803	9,661	11,149	11,196	11,299	11,661	12,090
Materials	3,693	4,104	4,560	4,606	4,758	4,791	4,862
Transportation and Equipment	3,940	4,264	4,500	4,562	4,680	4,807	4,920
Other Non Labor	1,802	2,240	2,044	1,929	1,920	1,907	1,933
Total Non Labor	**42,110**	**56,845**	**51,604**	**51,454**	**53,234**	**53,396**	**54,672**
Total O&M Expense - Mgmt. View	**65,891**	**83,271**	**77,037**	**78,031**	**80,253**	**81,774**	**83,842**
Plus:							
Base Gross Margin Items	-	-	-	-	-	-	-
Merchanism Gross Margin Items	-	-	-	-	-	-	-
	-	**-**	**-**	**-**	**-**	**-**	**-**
Total O&M Expense-GAAP View	**65,891**	**83,271**	**77,037**	**78,031**	**80,253**	**81,774**	**83,842**

[1] Total Line Clearance including labor is $21.7M for 2017, $24.6M for 2018, $25.6M for 2019, $25.5M for 2020, $26.5M for 2021, $26.5M for 2022, and $27.0M for 2023.

[2] Total Storm Restoration including labor is $4.8M 2017, $15.5M for 2018, $6.5M for 2019, $6.7M for 2020, $6.9M for 2021, $7.0M for 2022, and $7.2M for 2023.

2017-2023 Annual O&M Expenses
Non Labor Category
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Line Clearance:							
Routine LGE	6,211	6,076	6,558	6,726	6,788	7,067	7,325
Routine KU	11,722	13,465	12,763	12,783	12,917	13,145	13,376
Sub-Total Routine	**17,933**	**19,541**	**19,322**	**19,509**	**19,705**	**20,212**	**20,701**
Hazard Tree LGE	1,356	1,700	1,854	1,784	1,939	1,740	1,740
Hazard Tree KU	1,540	2,494	3,518	3,242	3,934	3,525	3,525
Sub-Total Hazard	**2,896**	**4,195**	**5,372**	**5,026**	**5,873**	**5,265**	**5,265**
Total Line Clearance	**20,829**	**23,736**	**24,693**	**24,535**	**25,578**	**25,477**	**25,966**
Storm Restoration - 3 yr. average:	**3,043**	**12,840**	**4,659**	**4,626**	**4,999**	**4,752**	**4,899**

		Total Expense			CPI	CPI Adjusted Amount				
		LG&E	KU	Total	Index	LG&E	KU	Total		
Normalized Storm Costs:										
	2017	2,267	2,533	4,800	1.0000	2,267	2,533	4,800		
	2016	2,305	2,841	5,146	1.0208	2,353	2,900	5,253		
	2015	4,844	3,606	8,451	1.0337	5,007	3,728	8,735		
Total		9,416	8,980	18,396		9,627	9,161	18,788		
Three Year Average						**3,209**	**3,054**	**6,263**		
Three Year Average - CPI Adjusted									Labor	Non Labor
	2018	6+6 Forecast			1.0163	**8,032**	**7,421**	**15,453**		
	2019				1.0367	**3,327**	**3,166**	**6,493**	**1,834**	**4,659**
	2020				1.0653	**3,419**	**3,253**	**6,672**	**2,046**	**4,626**
	2021				1.0939	**3,510**	**3,340**	**6,851**	**1,851**	**4,999**
	2022				1.1224	**3,602**	**3,428**	**7,029**	**2,277**	**4,752**
	2023				1.1469	**3,681**	**3,502**	**7,183**	**2,284**	**4,899**

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LG&E KU PPL companies

2017-2023 Annual O&M Expenses
Non Labor Category
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Outside Services - Supplemental:							
Asset Management (Includes Substations)	1,690	1,924	2,373	2,325	2,456	2,554	2,619
LGE Ops	3,675	3,809	4,388	4,635	4,820	5,071	5,318
KU Ops	344	1,200	1,958	1,985	2,017	2,050	2,066
Reliability	358	665	777	797	814	833	861
Estimated Impact for Additional Sales Tax	1	200	400	400	400	400	400
Total Outside Services - Supplemental	**6,067**	**7,798**	**9,896**	**10,142**	**10,508**	**10,908**	**11,264**
Outside Services - Other:							
Asset Management (Includes Substations)	436	390	86	91	89	91	92
LGE Ops	362	316	24	24	24	0	0
KU Ops	1,741	971	474	507	554	615	685
Reliability	182	180	636	401	93	16	17
Other	15	6	32	32	32	32	32
Total Outside Services - Other	**2,736**	**1,863**	**1,252**	**1,054**	**791**	**753**	**826**
Sub-Total Outside Services	**8,803**	**9,661**	**11,149**	**11,196**	**11,299**	**11,661**	**12,090**
Materials:							
Asset Management (Includes Substations)	949	1,110	1,188	1,210	1,259	1,257	1,301
LGE Ops	1,024	1,122	1,362	1,359	1,462	1,471	1,493
KU Ops	1,591	1,689	1,879	1,908	1,905	1,927	1,930
Reliability	103	155	103	101	105	108	110
Other	26	29	28	28	28	28	28
Total Materials	**3,693**	**4,104**	**4,560**	**4,606**	**4,758**	**4,791**	**4,862**

2017-2023 Annual O&M Expenses
Non Labor Category
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Transportation and Equipment:							
Asset Management (Includes Substations)	730	749	889	901	929	958	978
LGE Ops	858	947	934	950	963	987	1,008
KU Ops	2,331	2,537	2,643	2,676	2,753	2,827	2,898
Reliability	21	25	33	33	34	35	35
Other	1	6	1	1	1	1	1
Total Transportation and Equipment	**3,940**	**4,264**	**4,500**	**4,562**	**4,680**	**4,807**	**4,920**
Other Non Labor:							
Cellular/Paging Services	415	380	351	376	398	426	440
Meals	322	274	249	256	258	260	265
Liability Claims	303	667	406	406	406	406	406
Education and Training - Course Fees	202	252	112	125	141	144	152
Travel and Mileage Reimbursement	257	264	231	234	234	237	243
Dues and Subscriptions	52	43	124	124	124	124	124
Moving Expense	84	54	330	160	92	52	26
Fees, Permits, Licenses	92	35	41	41	41	41	41
Lease/Rentals	27	110	19	19	20	20	20
Other	49	161	181	188	206	197	217
Total Other Non Labor	**1,802**	**2,240**	**2,044**	**1,929**	**1,920**	**1,907**	**1,933**

O&M Annual Expense Reconciliation ($000)

	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
2018 Plan/Expectation	76,755	77,643	79,765	81,168	84,284
Drivers:					
Storm Restoration - 3 year average	(801)	(820)	(841)	(859)	(827)
Pole Attachment Mapping Asset	417	288	0	0	0
Estimated Sales Tax on Services	400	400	400	400	400
WFP and Other Labor Impacts	235	250	257	371	383
KU Distribution Operations	215	252	240	238	333
LG&E Distribution Operations	50	135	217	292	464
Other	(234)	(117)	215	164	(1,195)
Current Plan - Mgt. View	77,037	78,031	80,253	81,774	83,842

2017-2023 Capital Expenditures
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
New Business	69,972	67,672	72,927	74,528	77,421	80,733	83,851
Enhance the Network	49,811	84,086	102,831	87,550	87,995	57,968	63,327
Maintain the Network	63,415	74,390	90,751	85,679	87,028	70,365	70,805
Repair the Network	14,007	15,121	15,759	16,119	16,595	17,104	17,581
Miscellaneous	1,832	2,676	2,369	2,272	1,505	1,405	1,507
Total Capital	**199,037**	**243,945**	**284,637**	**266,148**	**270,544**	**227,575**	**237,071**
2018 Plan		**231,460**	**258,538**	**259,673**	**252,768**	**203,530**	**207,601**
Change		**12,485**	**26,099**	**6,475**	**17,776**	**24,045**	**29,470**

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Labor Expense

Salary Plan	2019 Average Headcount	2019 Base Salary	2019 Overtime and all Other Labor*	2019 TIA Labor Expense	2019 Total Salary & TIA Labor	2019 Labor Expense	2020 Labor Expense	2021 Labor Expense	2022 Labor Expense	2023 Labor Expense
Exempt	175	$ 19,218	$ -	$ 1,642	$ 20,860					
Non-Exempt	102	$ 7,434	$ 1,185	$ 781	$ 9,400					
Union / Non-Union Hourly	453	$ 36,606	$ 9,487	$ 3,406	$ 49,499					
Subtotal	730	$ 63,258	$ 10,672	$ 5,829	$ 79,759					
Co-ops / Interns	14	$ 302	$ -		$ 302					
Total	744	$ 63,560	$ 10,672	$ 5,829	$ 80,061	$25,433	$26,577	$27,019	$28,378	$29,170

Note: Annual expense amounts are on an income statement basis and exclude balance sheet accounts.

Employee Headcount by Work Group

Work Group or Major Dept.	Jun 30, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
VP	2	2	2	2	2	2	2
System Restoration and LG&E Operations	217	224	221	224	222	223	223
Reliability, Analytics & Administration	55	56	58	58	58	58	58
KU Distribution Operations	304	303	303	303	303	303	303
Substations & Asset Management	139	146	146	147	146	146	146
Interns	15	15	13	13	13	13	13
Total	732	746	743	747	744	745	745

Supplemental Contractors by Work Group

Work Group or Type of Work	June 30, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
Director, Electric Distribution - KU	200	211	257	237	241	193	204
Director, Substations and Asset Management	29	28	28	28	28	28	28
Director, Distribution Reliability Analytics Admin	374	399	398	398	398	398	375
Director, Distribution Ops and Emergency Preparedness	313	339	385	364	368	320	331
Total	**916**	**977**	**1,068**	**1,027**	**1,035**	**939**	**938**

2017-2023 Headcount Totals & Changes

Employees	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
TOTAL From Page 20	724	746	743	747	744	745	745
Prior Plan		736	731	735	732	732	
Change from Prior Plan		10	12	12	12	13	

	2018 FC	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Supplemental Contractors (Page 21)	977	1068	1027	1035	939	938
Prior Plan	902	922	931	931	931	
Change from Prior Plan	75	146	96	104	8	

Total Workforce (Employees Plus Supplemental Contractors)

	2018	2019	2020	2021	2022	2023
Current Plan	1,723	1,811	1,774	1,779	1,684	1,683
Prior Plan	1,638	1,653	1,666	1,663	1,663	
Change from Prior Plan	85	158	108	116	21	

Plan Risks

- Abnormal or unexpected grid exposure to severe weather, periods of temperature extremes, natural disasters, or physical and cyber attacks, resulting in increased distribution grid trouble or damages
- Continued / increased mutual assistance efforts impacting availability of supplemental and off-system contractor resources
- Accelerated reliability impacts associated with emerald ash borer and hazard trees, or other grid vulnerabilities
- Substantial deviations from economic forecasts or system load plans.
- Unpredicted increases in material, contractor labor, or equipment costs
- Unforeseen market penetrations of distributed energy resources, including distributed generation and electric vehicles
- Accelerated retirements/loss of key technical skillsets and increased competition for qualified resources in the industry
- Unforeseen regulatory rulings which require substantial changes to legacy system operations, maintenance, or construction practices

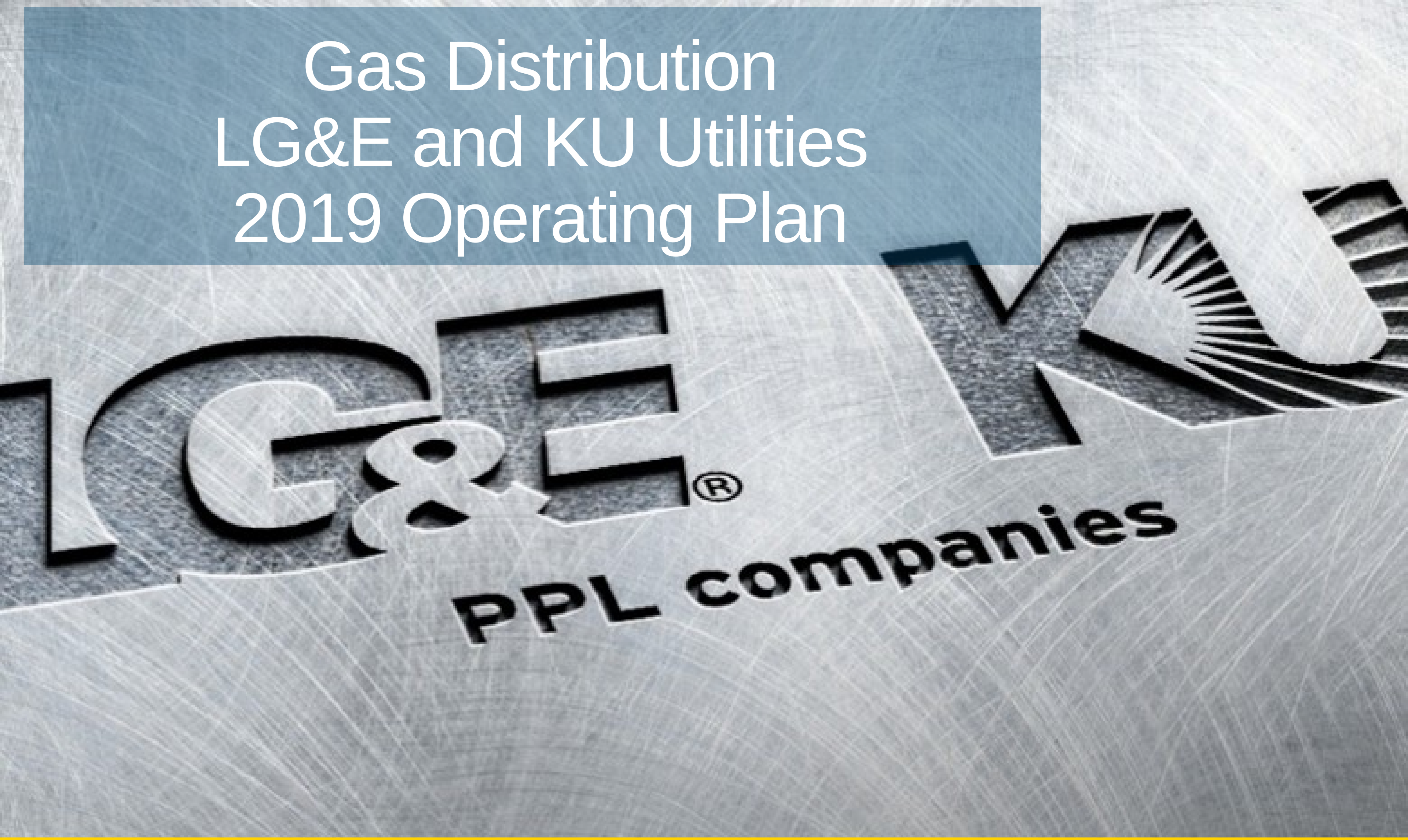
Operational Performance

Key Performance Indicators

KPI	2017 Year End	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Safety - Employees Incident Rate [1]	1.70	0.67	1.80	1.73	1.66	1.55	1.47
Safety - Contractors Incident Rate [1]	2.31	0.78	1.80	1.73	1.66	1.55	1.47
DART - Employees [1]	1.13	0.67	0.72	0.67	0.63	0.63	0.59
SAIFI	0.743	0.803	0.748	0.710	0.688	0.671	0.657
SAIDI	69.43	81.40	78.54	75.89	74.26	72.46	72.03
Residential New Business Cycle Time (Business Days) [2]	2.69	3.00	3.00	3.00	3.00	3.00	3.00
Repair Street Lights (Business Days) [3]	1.68	2.00	2.00	2.00	2.00	2.00	2.00
Electric Trouble Arrival Response Time (Minutes) [4]	42.55	45.00	45.00	45.00	45.00	45.00	45.00
Estimated Restoration Time (ERT) Accuracy [5]	96.5%	94%	95%	95%	95%	95%	95%
Cash Cost Per MWH Sold - 5 Yr. Avg. Calculation	7.43	8.29	9.19	10.02	10.69	11.14	11.21

1) 2018 Forecast numbers are YTD May 2018 actuals and not forecasted.
2) Measures the time between the approved inspection and the connection to the customer.
3) Measures the duration from once the call is received to when we are onsite to assess / repair.
4) Measures the time frame between the first call and arrival time for emergency calls on Blue Sky Days only.
5) Measures the percentage that service is restored on or before the ERT.

Gas Distribution
LG&E and KU Utilities
2019 Operating Plan



September 2018 – Updated to reflect KPSC AMS ruling

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Plan Highlights

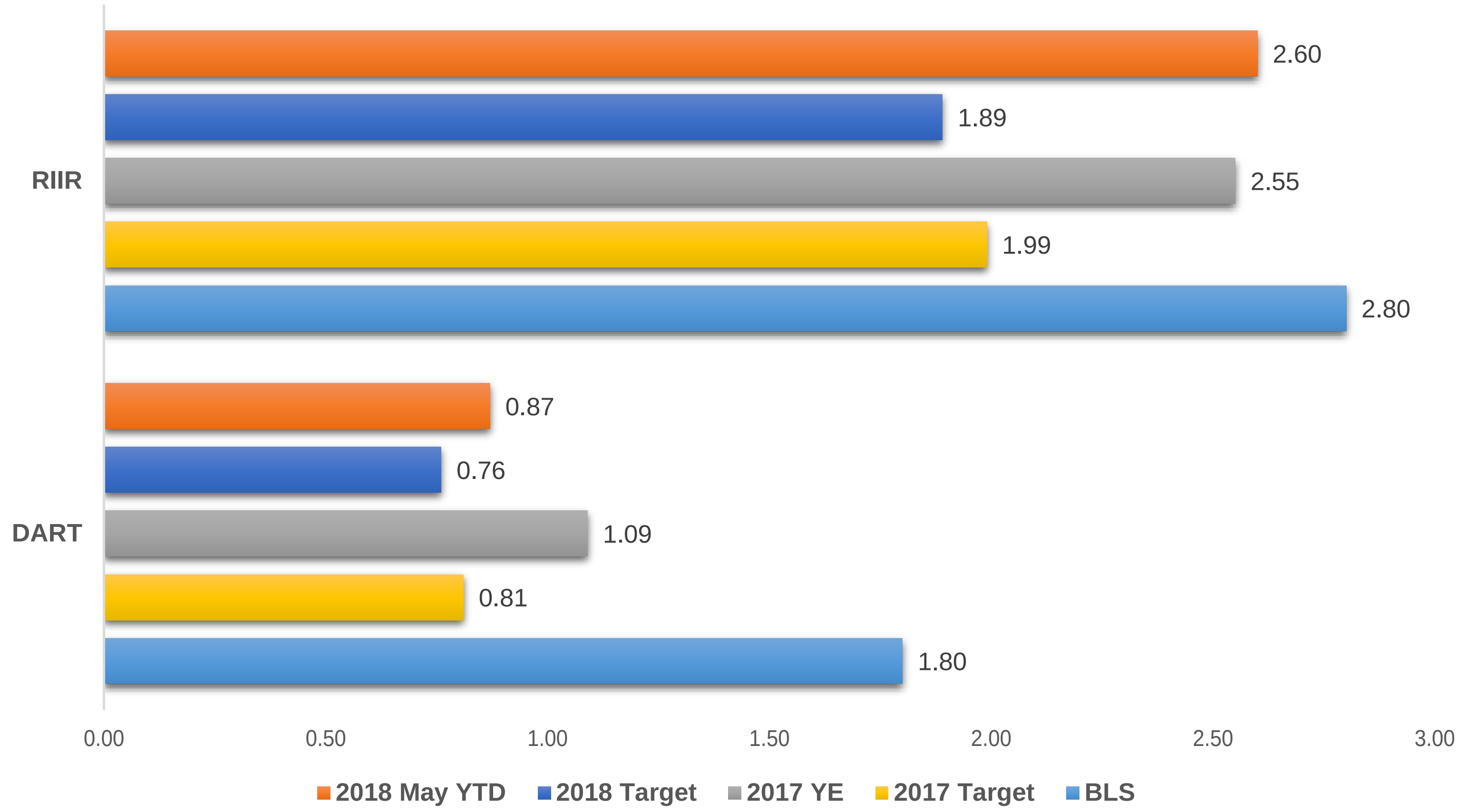
Safety and customer satisfaction are core values at LG&E and KU. Gas Distribution Operations mission is to provide safe, reliable, and low cost service that enhances our customer's quality of life.

Funding levels within the proposed plan were established with the following priorities in mind:

- Employee, contractor and public safety
- Regulatory compliance
- Supporting customer service
- Gas system reliability
- Asset replacement to ensure reliable and safe service
- System enhancements to meet customer needs
- Technology to increase efficiencies and enhance customer experience
- Capital investments for transmission modernization, customer service line replacement and service line ownership

Plan Highlights

Safety Performance - Gas



2016 BLS - most recent data

Plan Highlights

- Safety and Wellness
  - Continuously strive to improve employee safety performance
  - Improve gas system safety thru effective Distribution Integrity, Transmission Integrity, Public Awareness, Damage Prevention, Storage Integrity and Gas Control Room Management programs
  - Maintain strong safety partnerships with business partners
  - Enhanced public safety through customer communications and asset replacement
  - Continuation of motor vehicle safety initiatives
  - Identify, share, and capitalize on industry best practices
  - Mock drills, leak detection training, and emergency response improvements
  - Effective liaison with emergency response agencies
  - Promote wellness initiatives as an aspect of safety

Plan Highlights

- Customer Experience
  - — Meet customer expectations for new service requests
  - — Promptly address customer service issues
  - — Identify customer service improvement opportunities
  - — Invest in aging infrastructure to ensure reliable and safe service
  - — Promote professional and positive corporate image to customers
  - — Restore customer service outages quickly and efficiently
  - — Meet customer capacity needs
  - — Implement technology to support customer service
  - — Proactively communicate with customers

Plan Highlights

- Reliability, Infrastructure and Regulatory Compliance
  - — Investments in infrastructure to meet customer needs
  - — Investment in aging infrastructure to improve safety, reliability and performance
  - — Effectively manage gas distribution integrity, transmission integrity, storage integrity and control room management regulatory programs
  - — Provide reliable gas supplies through investments in:
    - Gas regulation/measurement facilities
    - Gas transmission system
    - Gas compressor stations
    - Gas storage fields
    - Distribution infrastructure upgrades

Plan Highlights

- Workforce Development
  - Headcount plan that addresses high number of expected retirements
  - Identification of pre-hires for critical job positions
  - Knowledge transfer to new employees
  - Support of employee continuing education initiatives
  - Support onboarding and enhanced training/operator qualification to promote consistent work practices across operational groups
  - Internal and external training opportunities
  - Mobile computing technologies supporting training
  - Skilled craft-worker intern program in participation with local technical colleges

Major Assumptions

- Customer expectations regarding levels of service and information availability will continue to increase.
- Incremental headcount is needed to meet increased regulatory, work scope and compliance demands, and transfer critical knowledge in preparation for retirements.
- New Business assumes low to moderate customer growth and inflationary increases through the planning period with new commercial and industrial loads requiring gas main extensions and system reinforcements.
- Continuation of the Gas Line Tracker (GLT) mechanism through the planning period.
- Gas Supply Clause remains fundamentally unchanged.
- Incremental resources for the Gas Trouble department to improve Emergency Response Time remain through the planning period.
- Available technology and operating conditions will support successful enhanced in-line inspections.

Major Assumptions

- Continued focus on reliability initiatives and system reinforcement.
- New gas safety regulatory requirements will:
  - Require operators to validate MAOPs of gas transmission pipelines.
  - Expand pipeline integrity requirements beyond high consequence areas.
  - Expand operator qualification requirements to construction activities.
  - Require continuous improvement for distribution system integrity.
  - Require continued implementation of storage integrity compliance program.
- Based upon the 2019 BP:
  - Forecasted Design Day for 2018 is expected to increase to 682,000 Mcf/day from 680,000 Mcf/day estimated in the prior BP. During the current 5-year planning period, the forecasted Design Day is expected to gradually decrease to 670,000 Mcf/day.
  - The Transmission Modernization and Steel Customer Service line programs will continue infrastructure upgrades supporting compliance and reliability.
  - Replacement of amine gas processing systems with H2S scavenging systems will increase storage reliability, reduce environmental risks and reduce headcount to operate compressor stations.

2017-2023 Annual O&M Expenses
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Expenses Only:							
Labor	18,092	20,754	21,267	22,039	22,930	23,141	23,875
Inline Inspections	658	3,878	10,341	1,741	2,712	7,390	3,376
Outside Services - Supplemental	6,793	10,068	12,913	13,118	13,503	13,974	14,402
Outside Services - Other	1,389	1,784	3,227	3,253	3,233	3,400	3,255
Materials	3,894	3,289	3,532	3,706	3,778	3,801	3,851
Transportation and Equipment	2,163	2,266	2,770	2,778	2,879	2,934	2,971
All Other Non-labor	1,940	2,217	2,133	1,857	1,866	1,816	1,912
Total O&M Expense - Mgmt. View	**34,929**	**44,256**	**56,183**	**48,492**	**50,902**	**56,457**	**53,642**
Plus:							
Base Gross Margin Items	-	-	-	-	-	-	-
Mechanism Gross Margin Items	3,443	2,537	2,588	2,841	2,902	2,925	2,943
Total O&M Expense-GAAP View	**38,372**	**46,793**	**58,771**	**51,333**	**53,804**	**59,382**	**56,585**

2017-2023 Annual O&M Expenses Non Labor Category ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Inline Inspections:							
Ballardsville ILI	440	2	0	0	0	0	0
Calvary ILI	156	134	0	0	0	0	0
Center 20" ILI	0	1,362	0	0	0	0	0
Lees to Cane Run ILI	0	494	0	0	0	0	0
Magnolia 16" Line ILI	0	4	2,806	0	0	0	0
Mill Creek 12" ILI	0	194	0	0	0	0	0
Muldraugh-Piccadilly ILI	0	1,567	0	0	0	0	0
Western Kentucky A Line ILI	0	0	2,465	0	0	4,560	0
Penile to Paddy's 16" & 20" Line ILI	0	0	5,070	0	0	0	0
Western Kentucky B Line ILI	0	0	0	1,741	0	2,280	0
Magnolia 20" line - Radcliff to Magnolia ILI	0	0	0	0	2,712	0	0
Riverport 12" ILI	0	0	0	0	0	550	0
Riverport 8" ILI	0	0	0	0	0	0	567
Doe Valley 8" ILI	0	0	0	0	0	0	2,809
Pipeline Repairs / Validation Digs	62	121	0	0	0	0	0
Total Inline Insepctions	**658**	**3,878**	**10,341**	**1,741**	**2,712**	**7,390**	**3,376**
Outside Services - Supplemental:							
LGE Electric and Gas Line Locating	3,433	4,749	8,301	8,301	8,594	8,910	9,277
Stop Box Inspections	1,224	1,741	1,662	1,665	1,659	1,715	1,738
Corrosion Control	554	976	783	799	815	831	848
Leak Survey	579	592	847	850	863	906	912
Gas Distribution	627	1,388	685	872	939	963	973
Estimated impact for additional sales tax	0	160	320	320	320	320	320
Other	376	462	315	311	313	329	334
Total Outside Services - Supplemental	**6,793**	**10,068**	**12,913**	**13,118**	**13,503**	**13,974**	**14,402**

2017-2023 Annual O&M Expenses
Non Labor Category
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Outside Services - Other:							
Compressor Stations	629	631	1,061	1,380	1,322	1,465	1,435
Storage Integrity and Internal Corrosion	318	349	863	774	725	759	777
Gas Control	213	184	371	337	355	373	428
Transmission Integrity and Compliance	129	428	616	415	462	419	223
Distribution Integrity and Compliance	-	4	220	227	244	259	268
Other	100	188	96	120	125	125	124
Total Outside Services - Other	**1,389**	**1,784**	**3,227**	**3,253**	**3,233**	**3,400**	**3,255**
Materials:							
Compressor Stations	1,748	1,324	1,528	1,522	1,581	1,576	1,599
Gas Control	414	331	374	373	373	373	373
Transmission Integrity and Compliance	539	498	554	554	554	554	554
Distribution Integrity and Compliance	85	105	189	189	197	218	237
Gas Distribution	1,098	995	837	1,016	1,021	1,025	1,028
Other	10	36	50	52	52	55	60
Total Materials	**3,894**	**3,289**	**3,532**	**3,706**	**3,778**	**3,801**	**3,851**
Transportation and Equipment:							
Compressor Stations	822	763	950	942	962	962	977
Gas Control	347	321	410	431	442	450	457
Transmission Integrity and Compliance	137	181	240	244	248	277	281
Distribution Integrity and Compliance	57	101	114	117	119	121	123
Gas Distribution	791	884	1,011	1,000	1,064	1,079	1,088
Other	9	16	45	44	44	45	45
Total Transportation and Equipment	**2,163**	**2,266**	**2,770**	**2,778**	**2,879**	**2,934**	**2,971**

2017-2023 Annual O&M Expenses
Non Labor Category
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Other Non Labor:							
AGA Dues	195	202	195	195	195	195	195
Dues and Subscriptions - Other	172	151	158	158	158	158	160
Phone and Telecom	189	171	169	174	174	155	155
Fees, Permits, and Licenses	218	254	197	197	197	197	197
Utilities	257	137	183	183	183	183	183
Travel and Mileage Reimbursement	134	128	150	136	138	139	133
Liability Claims	10	115	131	131	131	131	131
Education and Training	87	164	180	164	168	180	181
Meals	110	82	86	86	84	87	89
Lease/Rentals	20	19	18	18	18	12	12
Computer Hardware/Software	104	31	28	28	28	28	28
Other Operating Expenses	444	763	638	387	392	351	448
Total Other Non Labor	**1,940**	**2,217**	**2,133**	**1,857**	**1,866**	**1,816**	**1,912**

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2017-2023 Annual Expenses Mechanism Gross Margin Items ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
GLT:							
CSO Meter Conditions	385	419	559	581	600	614	626
Repair Leaks	245	360	280	281	284	289	291
Other GLT	(76)	(5)	(33)	214	219	223	227
Total GLT	**554**	**774**	**806**	**1,076**	**1,103**	**1,126**	**1,144**
Gas Losses:							
Muldraugh [1]	2,679	1,534	1,571	1,553	1,588	1,588	1,588
Magnolia [2]	210	229	211	212	211	211	211
Total Gas Losses	**2,889**	**1,763**	**1,782**	**1,765**	**1,799**	**1,799**	**1,799**
Total Mechanism Gross Margin	**3,443**	**2,537**	**2,588**	**2,841**	**2,902**	**2,925**	**2,943**

[1] Muldraugh: 2019 gas losses based on 433 MMcf at $3.63/MMcf for a total $1.6M, 2020 is 433 MMcf at $3.59/MMcf for a total $1.6M, and 2021-2023 is 433 MMcf at $3.67/MMcf for a total $1.6M.

[2] Magnolia: 2019 gas losses based on 58.6 MMcf at $3.61/MMcf for a total $.2M, 2020 is 58.6 MMcf at $3.62/MMcf for a total $.2M, and 2021-2023 is 58.6 MMcf at $3.61/MMcf for a total $.2M.

O&M Annual Expense Reconciliation ($000)

	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
2018 Plan/Expectation	41,458	41,010	41,999	42,921	44,762
Drivers:					
In Line Inspections	8,031	792	2,164	6,828	2,369
Line Locating	5,066	5,066	5,277	5,508	5,844
Distribution Integrity Management Plan	413	376	384	399	410
Leak Survey	393	395	396	427	429
Stop Box Inspections	376	366	327	359	371
Emergency Response Improvements	800	820	841	862	883
Estimated Sales Tax on Services	320	320	320	320	320
Close Interval Survey	290	84	116	20	60
WFP Impacts - All Other	371	235	169	240	247
WFP Impacts - Savings from Amine Plant Rep	(381)	(480)	(964)	(1,145)	(1,180)
Overtime Reductions	(1,237)	(873)	0	0	0
Other	283	381	(127)	(282)	(873)
Current Plan - Mgt. View	56,183	48,492	50,902	56,457	53,642

2017-2023 Capital Expenditures
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
New Business	9,296	9,956	8,634	8,893	9,156	9,336	9,617
Enhance the Network	26,614	58,404	98,180	65,515	82,623	46,012	45,002
Maintain the Network	40,224	33,066	38,916	28,585	31,221	21,772	20,650
Repair the Network	381	768	378	389	400	413	425
Miscellanous	1,283	1,082	892	624	1,196	382	391
Total Capital	**77,798**	**103,276**	**146,999**	**104,005**	**124,596**	**77,915**	**76,085**
2018 Plan		**114,751**	**129,361**	**100,568**	**85,697**	**62,923**	**71,440**
Change		**(11,475)**	**17,638**	**3,437**	**38,899**	**14,992**	**4,645**

Labor Expense

	2019									
Salary Plan	Average Headcount	Base Salary	Overtime and all Other Labor*	TIA Labor Expense	Total Salary & TIA Labor	2019 Labor Expense	2020 Labor Expense	2021 Labor Expense	2022 Labor Expense	2023 Labor Expense
Exempt	104	$ 10,776	$ -	$ 840	$ 11,616					
Non-Exempt	24	$ 1,322	$ 75	$ 127	$ 1,524					
Union / Non-Union Hourly	174	$ 13,169	$ 2,742	$ 1,258	$ 17,169					
Subtotal	303	$ 25,267	$ 2,817	$ 2,225	$ 30,309					
Co-ops / Interns	7	$ 161	$ -	$ -	$ 161					
Total	**310**	**$ 25,428**	**$ 2,817**	**$ 2,225**	**$ 30,470**	**$ 21,267**	**$ 22,039**	**$ 22,930**	**$ 23,141**	**$ 23,875**

Note: Annual expense amounts are on an income statement basis and exclude balance sheet accounts.

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Employee Headcount by Work Group

Work Group or Major Dept.	June 30, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
VP Gas Distribution Operations	2	2	2	2	2	2	2
Transmission Integrity & Compliance	22	24	24	23	23	23	23
Distribution Integrity & Compliance	15	21	22	21	21	21	21
Pipeline Safety Management Systems	2	3	4	4	4	4	4
Operator Qualifications Program	1	2	4	4	4	4	4
Compliance/Environmental Coordinator	1	1	1	1	1	1	1
Gas Management & Supply	6	6	6	6	6	6	6
Gas Operations, Constructions, & Engineering	120	128	128	128	128	128	128
Gas Control & Storage	97	110	111	110	103	102	102
Interns	10	10	7	7	7	7	7
Total	**276**	**307**	**309**	**306**	**299**	**298**	**298**

Supplemental Contractors by Work Group

Work Group or Type of Work	Jun 30, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
Director, Gas Control & Storage	10	10	10	10	10	10	10
Director, Gas Operations Construction & Engineering	170	169	176	176	166	163	163
Manager, Gas Transmission Integrity & Compliance	9	11	11	11	11	11	11
Manager, Gas Distribution Integrity & Compliance	112	112	112	112	112	112	112
Total	**301**	**302**	**309**	**309**	**299**	**296**	**296**

2017-2023 Headcount Totals & Changes

	Year-End						
	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Employees							
TOTAL From Page 19	**264**	**307**	**309**	**306**	**299**	**298**	**298**
Prior Plan		300	301	301	299	298	
Change From Prior Plan		7	8	5	0	0	

	2018 FC	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Supplemental Contractors (Page 20)	302	309	309	299	296	296
Prior Plan	261	260	260	260	260	
Change from Prior Plan	41	49	49	39	36	

Total Workforce (Employees Plus Supplemental Contractors)

Current Plan	609	618	615	598	594	594
Prior Plan	561	561	561	559	558	
Change from Prior Plan	48	57	54	39	36	

Plan Risks

- Finalization of new transmission pipeline regulations
- Regulatory changes impacting capital and O&M costs
- Mitigation costs associated with gas transmission pipeline inspections
- Mitigation costs associated with new storage integrity compliance requirements
- Economic development-pace
- Impact of workforce turnover from retirements
- Overtime needs exceeding overtime assumed in the plan
- Material, equipment, and resource cost escalation and availability
- Permitting and Right of Way acquisition for Pipeline projects

Plan Risks

- Findings from failure analysis on longitudinal defect on Ballardsville gas transmission pipeline could drive capital or O&M incremental to the plan.
- Aggressive KPSC enforcement of gas safety regulations and KY "Before you Dig" laws
  - Increased citations/fines
  - Increased underground locating costs
- Telecommunications fiber projects and other general construction increases driving increase in line locating costs

Operational Performance

Key Performance Indicators

KPI	2017 Year End	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Safety - Employee Incident Rate [1]	2.55	2.60	1.80	1.73	1.66	1.55	1.47
Safety - Contractors Incident Rate [1]	1.58	0.00	1.80	1.73	1.66	1.55	1.47
DART - Employees [1]	1.09	0.87	0.72	0.67	0.63	0.63	0.59
Gas Response Priority 1 Calls (minutes)	37.1	35.6	35.0	34.5	34.0	33.5	33.0
New Business Cycle Time (Calendar Days) [2]	6.00	9.00	9.00	9.00	9.00	9.00	9.00

1) 2018 Forecast numbers are YTD May 2018 actuals and not forecasted.
2) Measures from the time a service request is approved by a locator from the Design department to the time the service is installed.

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Transmission
LG&E and KU Utilities
2019 Operating Plan

August 2018

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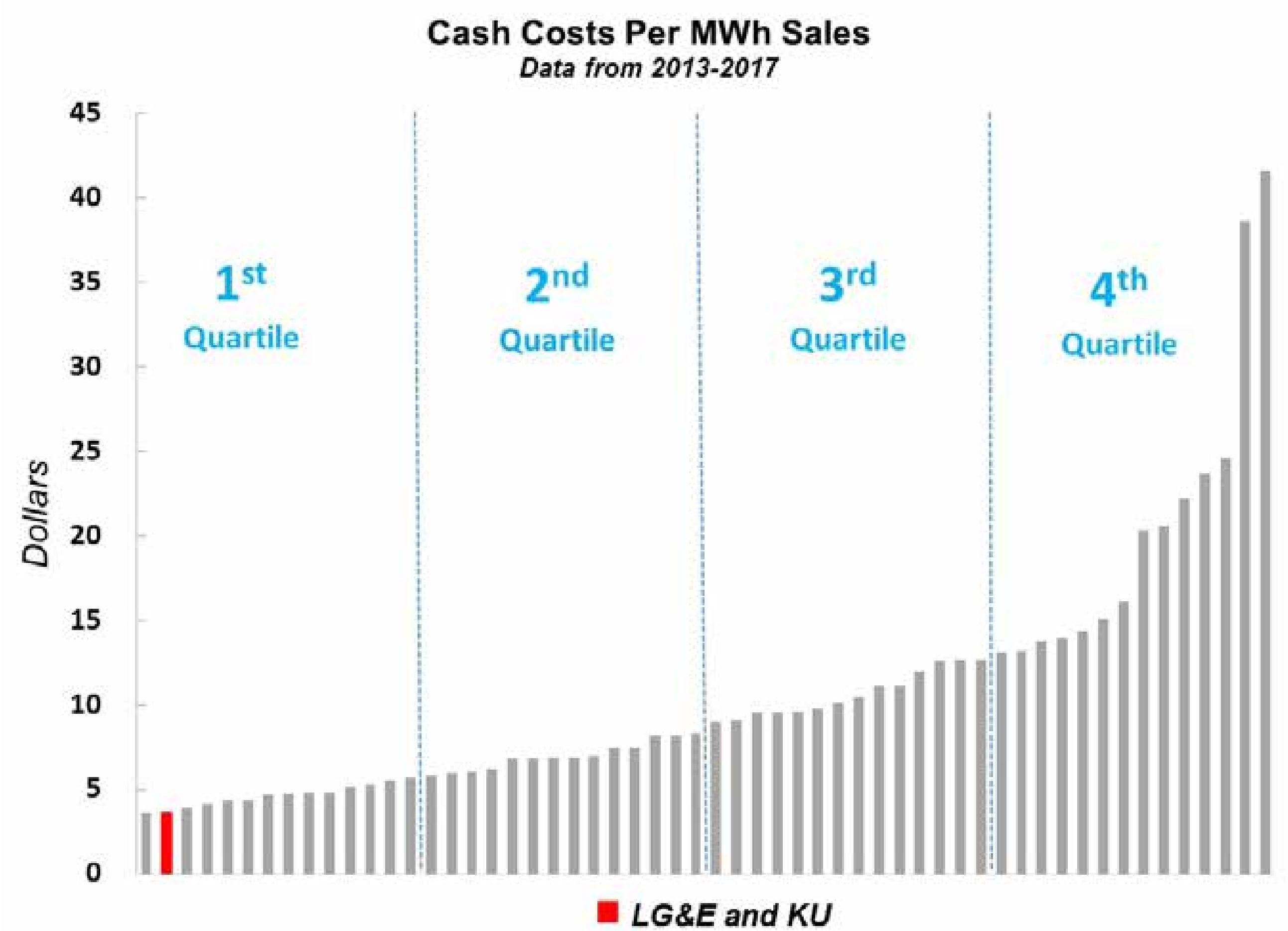
Plan Highlights

1. The overall objective of the 2019-2023 Transmission Business Plan is to invest in the system to accommodate network load flows with a focus on improving system reliability and resiliency at a fair and reasonable cost. The work will be completed while maintaining a strong culture of safety, customer experience, performance, and regulatory compliance.
2. Data analytics will continue to be utilized to improve performance by identifying projects that will reduce outage frequency and duration. Programs in the plan are primarily a continuation of those initiated in 2017 as part of the Transmission System Improvement Plan.
3. Transmission line and substation projects approved by the Independent Transmission Organization (ITO) driven by NERC planning standards and LG&E and KU system planning guidelines to ensure electric grid adequacy to reliably serve forecasted network flow in light and heavy load periods.
4. Targeted replacement of small copper and single layer aluminum conductor steel-reinforced (ACSR) conductor.
5. Reduction of the transmission wood pole back log from a multi-year back log to a targeted single-year backlog by the end of the plan period.
6. Transmission line extensions to serve new distribution substations for retail customers.
7. Security initiatives including the protection of critical facilities from physical attacks and vandalism.
8. Resiliency initiatives to both harden the system to withstand catastrophic events as well as improve our ability to recover should we have an event.
9. Will have replaced all underground transmission cable that has experienced diminishing performance with observed failures.

Plan Highlights
FERC Benchmarking Data



Cash cost benchmarking analysis includes Transmission O&M and capital costs per MWh company sales compared to other utilities.

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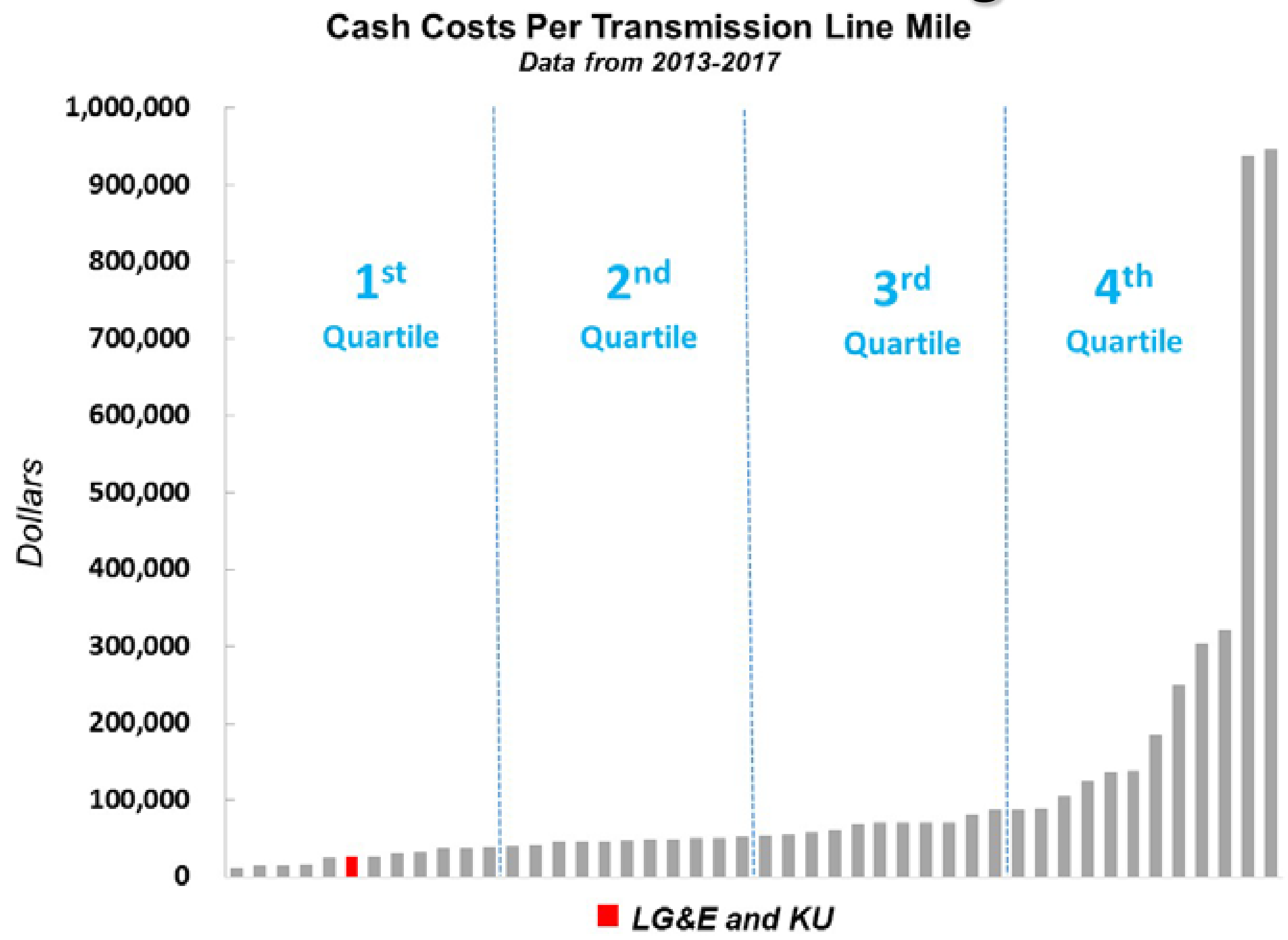
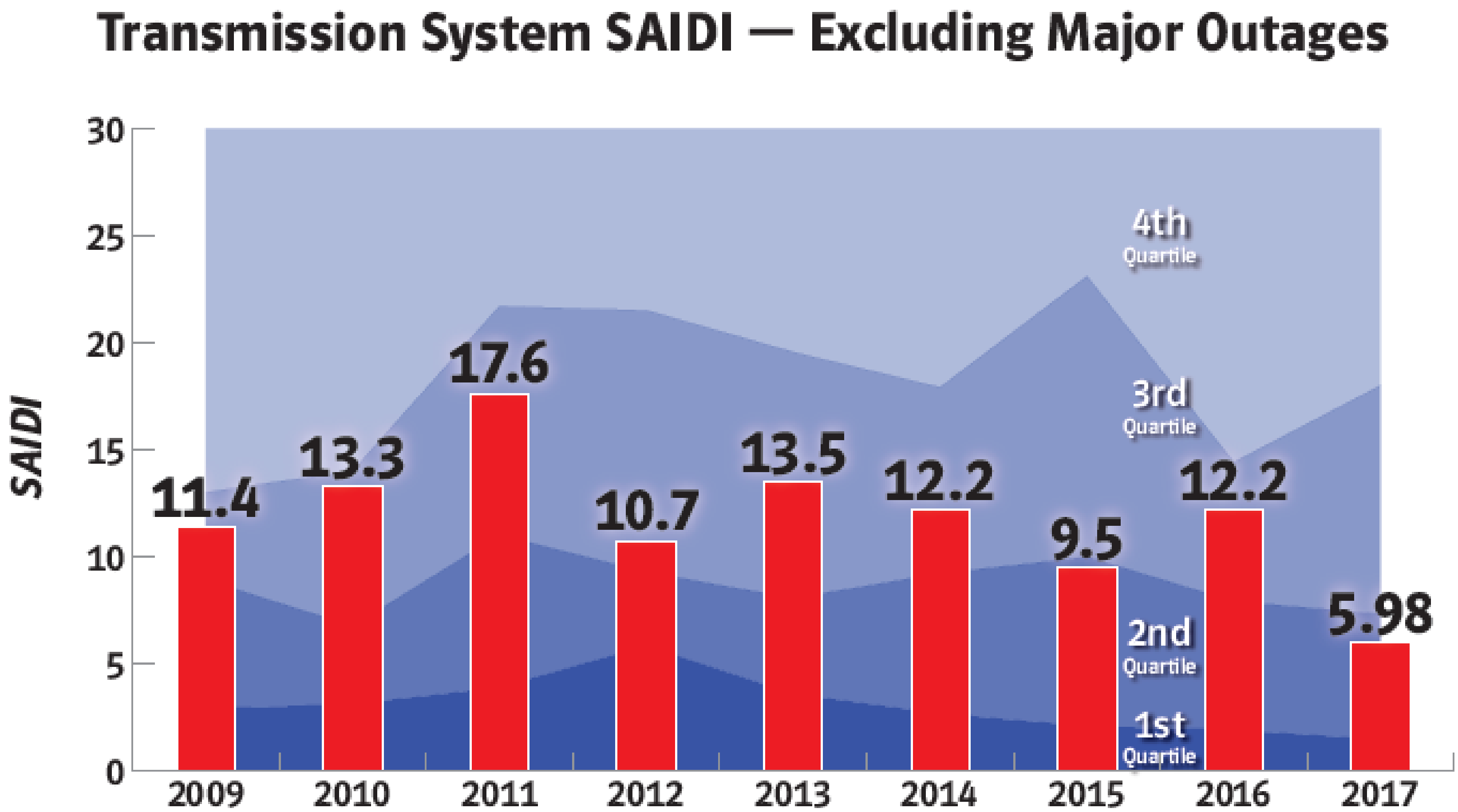
Plan Highlights
FERC Benchmarking Data



Cash cost benchmarking analysis includes Transmission O&M and capital costs per transmission line mile compared to other utilities.

Plan Highlights
Historical Reliability Performance



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LG&E KU
PPL companies

Major Assumptions

Reliability, Operations and Asset Management:

1. Reliability improvement – Data Analytics will be utilized to prioritize line segments based on past performance and overall risk. Programs include:

   i. Line Sectionalizing - Segmenting circuits with equipment to reduce customer exposure from sustained outages and improve restoration time.

   ii. Enhanced vegetation clearing will reduce sustained and momentary outages:

   - Line vegetation clearing began transitioning from an inspection based program to a 5 year maintenance cycle in 2017 for all lines 69kV and higher. The first cycle will continue through 2022.
   - A hazard tree identification and removal program continues to reduce the probability of dead, dying, and diseased trees from falling on transmission lines.

2. System Integrity - Enhanced transmission asset management will effectively improve the performance and reliability of the assets over time:

   i. Structure, cross arm and insulator replacements based on condition determined by detailed inspections. Pole backlog will be reduced from approximately 2,900 in 2018 to a targeted single-year backlog (~ 250) by the end of the plan period.

   ii. Overhead line conductor and static wire replacements are based on age, type (e.g. copper and single layer ACSR) and condition of conductor.

   iii. Control house and related protection and control replacements based on risk, age, condition and performance.

   iv. Circuit breaker replacements based on risk, age, condition and maintainability.

   v. Extend life of tower and substation structural steel through condition assessment and enhanced maintenance including corrosion prevention and control.

   vi. Optimize asset lifecycle of substation equipment including circuit breakers and transformers through diagnostics.

3. Storm damage and emergency replacement costs are based on past trends.

Major Assumptions

Transmission Expansion Plan (TEP) and Native Load:

1. Projects are based on the 2018 TEP, which has been submitted to the ITO for approval, and initial analysis for the 2019 TEP, which includes transmission customer demand forecasts submitted in the fall of 2017. It is assumed those customer forecasts are reasonable and that the Independent Transmission Organization (ITO) will approve the 2018 & 2019 TEPs without significant revisions.
2. The TEP includes funding for rating increases to certain transmission lines based on estimates. Detailed costs will be developed after surveying and subsequent analyses are completed.
3. No funding needed to accommodate new long term, firm transmission service requests that have not already been requested or studied.
4. Connection costs for native load are coordinated with the Electric Distribution planning requirements.

Regulatory and Compliance:

1. Assessments of the system for impact from a Geomagnetic Disturbance (GMD) will not result in risks requiring material expenditures to mitigate.
2. Expenditures related to mitigating Electromagnetic Pulse (EMP) events are not anticipated during the plan period.
3. Additional revisions to NERC Reliability standards will not require material incremental expenditures beyond what is funded in this plan.
4. Regional and interregional planning processes as required by FERC Order 1000 will not result in material capital or O&M expenditures.

Major Assumptions

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Open Access Transmission Tariff (OATT) Revenue are based on the following:

1. Customer provided load forecasts have been evaluated and adjusted, based on historical performance, to reflect their expected coincident peak billing amount.
2. OATT rate forecast is based on 2017 FERC Form 1 data, the FERC approved rate formula and ROE, and 2019 Business Plan projections, including O&M and capital.
3. [redacted] will not renew its existing point to point (PTP) reservations at the end of their respective terms (2019, 2020, and 2022). This assumption is based on the announcement that [redacted] to retire [redacted] over the plan period.
4. Assumed short term and non-firm revenue of $650K, based on the 2015-2017 annual average.
5. Joint Party Settlement revenue of $1.2m annually is assumed to continue through the duration of the business plan.

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Major Assumptions

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Cost of Sales assume the following:

1. MISO transmission rates used to calculate merger mitigation depancaking (MMD) expenses per Rate Schedule 402:
   - For Scheduled 26A, the posted MISO rate is used and multiplied by the volume which is determined by a load factor of 55%.
   - Schedules 7 & 8 are adjusted at an annual increase of 5% starting with the April 2018 rate. The 5% annual increase reflects the 10 year historical rate of change prior to the recent federal tax decrease. The April 2018 rate is the starting point and includes impacts of the federal tax law decrease.
   - MISO resources for Kentucky Municipal Electric Agency (KYMEA), those assumed to be eligible for depancaking, are based on existing MISO resources – 20 MWs through April 2019, 200 MWs starting in May 2019 – December 2022. 100 MWs of a non-MISO resource, not eligible for de-pancaked rates, expires on 4/30/22 and this is assumed to be replaced from a non-MISO source.
2. MMD expense includes MISO PTP service purchased by [redacted] for 115 MWs with a term of February 2018 – January.
3. TranServ will continue as the ITO service provider at costs based on the existing agreement.
4. TVA will remain as the Reliability Coordinator (RC) at costs based on the existing agreement.

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2017-2023 Annual O&M Expenses
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Expenses Only:							
Labor	$12,527	$12,534	$12,341	$12,631	$12,902	$13,061	$13,373
Vegetation Management	10,031	14,242	14,613	14,053	15,153	13,817	14,284
Lines Asset Management	2,202	3,738	4,106	4,368	4,372	4,400	4,829
Substation and Protection	3,748	4,209	3,993	4,204	4,430	4,286	3,659
Operations and Compliance	2,860	3,072	3,237	3,312	3,389	3,471	3,548
Planning, Tariffs and Reliability Perf.	257	351	425	427	429	431	433
All Other Non-labor	311	322	312	312	312	312	312
Total O&M Expense - Mgmt. View	**$31,935**	**$38,468**	**$39,027**	**$39,306**	**$40,987**	**$39,777**	**$40,439**
Plus:							
Base Gross Margin Items	$14,874	$20,998	$28,455	$30,339	$30,812	$31,896	$33,687
Mechanism Gross Margin Items	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total O&M Expense-GAAP View	**$46,809**	**$59,466**	**$67,482**	**$69,645**	**$71,799**	**$71,673**	**$74,126**

2017-2023 Annual O&M Expenses Non Labor Vegetation Management ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Cycle Clearing	$ 8,891	$ 11,400	$ 12,199	$ 12,372	$ 12,572	$ 12,736	$ 13,324
345kV ROW Widening	828	1,641	1,333	600	1,500	-	-
Hazard Tree Removal	10	688	617	617	617	617	536
Hazard Tree Patrol	167	167	156	156	156	156	156
Emerald Ash Borer	135	345	308	308	308	308	268
Total	$ 10,031	$ 14,248	$ 14,613	$ 14,053	$ 15,153	$ 13,817	$ 14,284
Supplemental contract labor included above:	$ 4,823	$ 7,022	$ 8,762	$ 8,505	$ 9,148	$ 7,758	$ 7,792

2017-2023 Annual O&M Expenses
Non Labor Lines Asset Management
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Aerial Patrol	$ 739	$ 796	$ 945	$ 945	$ 945	$ 945	$ 945
Switch Maintenance	281	899	908	923	924	945	968
Corrosion Prevention	58	631	816	1,053	1,053	1,053	1,053
Wood and Steel Structure Inspection	66	77	153	156	160	164	409
Bulk Electric System LiDAR	142	210	200	200	200	200	200
Storm Restoration	256	374	366	377	377	379	381
All Other	661	752	718	713	713	713	873
Total	$ 2,202	$ 3,738	$ 4,106	$ 4,368	$ 4,372	$ 4,400	$ 4,829
Supplemental contract labor included above:	$ 809	$ 2,060	$ 2,967	$ 3,213	$ 3,292	$ 3,271	$ 3,303

2017-2023 Annual O&M Expenses
Non Labor Substation Maintenance
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Outside Services Labor	$ 1,764	$ 1,991	$ 1,908	$ 2,116	$ 2,313	$ 2,162	$ 1,723
Material	902	1,208	1,183	1,169	1,184	1,177	978
Vehicles	565	537	544	555	568	584	593
Training Travel Meals	135	174	144	144	144	144	145
Communications/Computer Equipment	193	202	213	213	213	213	213
All Other	189	97	-	6	6	6	6
Total	$ 3,748	$ 4,209	$ 3,993	$ 4,204	$ 4,430	$ 4,286	$ 3,659

2017-2023 Annual O&M Expenses
Non Labor Operations and Compliance
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
FERC	$ 766	$ 829	$ 883	$ 883	$ 883	$ 883	$ 883
NERC & SERC	1,009	1,099	1,154	1,203	1,254	1,308	1,364
IMEA & IMPA Reactive Power	223	222	223	223	223	223	223
System Operations - OATI	312	334	353	364	375	386	390
OSI/Primate/AVI BARCO	261	276	284	298	313	329	345
All Other	290	313	339	340	341	342	343
Total	$ 2,860	$ 3,072	$ 3,237	$ 3,312	$ 3,389	$ 3,471	$ 3,548

2017-2023 Annual O&M Expenses
Non Labor Planning, Tariffs & Reliability Performance
($000)

Item	2017 Actual	2018 Foreca	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Outside Services Labor	$ 20	$ 41	$ 83	$ 83	$ 83	$ 83	$ 83
Training	16	26	38	38	38	38	38
Travel	58	60	60	60	60	60	60
Meals	12	9	8	8	8	8	8
Computer / Communications	68	73	83	83	83	83	83
OATI Web Accounting & FERC 676-H	57	62	64	66	68	70	72
All Other	26	81	89	89	89	89	89
Total	$ 257	$ 351	$ 425	$ 427	$ 429	$ 431	$ 433

2017-2023 Annual Expenses
Base Gross Margin OATT Revenues
($000)

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	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
2019 BP OATT Revenue							
3rd Party	$ 23,755	$ 25,694	$ 24,669	$ 24,960	$ 27,468	$ 29,667	$ 29,905
Wholesale Customers	6,736	7,783	3,500	1,866	2,159	2,441	2,681
[redacted]	222	368	4,846	7,721	8,743	9,732	10,554
Joint Party Settlement	1,665	1,244	1,245	1,245	1,245	1,245	1,245
Total OATT Revenue	$ 32,378	$ 35,089	$ 34,260	$ 35,792	$ 39,615	$ 43,085	$ 44,385
2018 BP OATT Revenue							
3rd Party		$ 26,634	$ 28,126	$ 29,424	$ 32,399	$ 36,596	$ 41,352
Wholesale Customers		7,810	4,012	2,163	2,448	2,781	3,159
[redacted]		401	5,865	9,225	10,255	11,453	12,799
Joint Party Settlement		1,243	1,243	1,243	104	-	-
Total OATT Revenue		$ 36,088	$ 39,246	$ 42,055	$ 45,206	$ 50,830	$ 57,310
Variance, Fav / (Unfav)		$ (999)	$ (4,986)	$ (6,263)	$ (5,591)	$ (7,745)	$(12,925)

2017-2023 Annual Expenses
Base Gross Margin Cost of Sales Items
($000)

	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
2019 BP Cost of Sales							
Independent Transmission Operator	$ 2,682	$ 2,541	$ 2,571	$ 2,609	$ 2,648	$ 2,687	$ 2,727
Reliability Coordinator	2,487	2,537	2,588	2,640	2,692	2,746	2,801
Depancaking	9,705	15,920	23,295	25,090	25,472	26,463	28,159
Total Cost of Sales	$ 14,874	$ 20,998	$ 28,455	$ 30,339	$ 30,812	$ 31,896	$ 33,687
2018 BP Cost of Sales							
Independent Transmission Operator		$ 2,534	$ 2,571	$ 2,609	$ 2,648	$ 2,687	$ 2,727
Reliability Coordinator		2,537	2,588	2,640	2,692	2,746	2,801
Depancaking		12,950	24,642	28,449	30,090	32,495	34,256
Total Cost of Sales		$ 18,021	$ 29,801	$ 33,698	$ 35,430	$ 37,928	$ 39,784
Variance, Fav / (Unfav)		$ (2,977)	$ 1,346	$ 3,360	$ 4,618	$ 6,032	$ 6,097

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LG&E KU PPL companies

2017-2023 Annual Expenses
Base Gross Margin Items
($000)

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	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
[redacted] (forgiven LG&E/KU costs)	$ 1,822	$ 565	$ -	$ -	$ -
[redacted] (MISO bills paid)	5,353	5,796	6,060	6,312	6,574
[redacted] (MISO bills paid)	7,097	7,410	7,683	7,980	8,285
[redacted] (MISO bills paid)	8,676	10,972	11,382	11,824	12,953
Various SFP and NF(forgiven LG&E/KU costs)	347	347	347	347	347
Total	$ 23,295	$ 25,090	$ 25,472	$ 26,463	$ 28,159

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2017-2023 Annual Expenses
Base Gross Margin Items
($000)

Net Margin

	2019	2020	2021	2022	2023
2019 BP	$ 5,805	$ 5,453	$ 8,803	$ 11,189	$ 10,698
2018 BP	9,445	8,357	9,776	12,902	17,526
Variance, Fav / (Unfav)	$ (3,640)	$ (2,904)	$ (973)	$ (1,713)	$ (6,828)

O&M Annual Expense Reconciliation ($000)

	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Expectation	$39,128	$39,206	$40,887	$39,677	$40,339
Drivers:					
2018 Sales Tax Change	$ 100	$ 100	$ 100	$ 100	$ 100
Substation Maintenance	$ (201)				
Current Plan - Mgt. View	$39,027	$39,306	$40,987	$39,777	$40,439

2017-2023 Capital Expenditures
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Compliance	$ 2,265	$ 652	$ 405	$ 602	$ 428	$ 530	$ 4,483
Emergency Replacement	2,238	4,097	2,640	2,601	2,629	2,656	2,684
Native Load	4,408	5,095	1,441	5,553	2,428	625	2,984
Operations Support	544	564	2,042	3,350	1,765	1,385	1,151
Proactive Replacement	94,512	106,447	112,483	129,481	147,976	83,114	87,419
Reliability	11,528	10,034	15,694	14,678	15,548	8,568	4,853
Resiliency	11,634	11,782	11,729	3,628	8,664	3,536	10,232
Transmission Expansion Plan	5,649	5,596	22,484	28,432	43,815	19,601	6,118
Third Party Requests	634	24	403	1,358	1,066	-	-
Total Capital	$133,412	$144,291	$169,320	$189,684	$224,319	$120,016	$119,925
2018 Plan		$144,292	$168,757	$190,705	$224,519	$141,577	$141,608
Change		$ (1)	$ 563	$ (1,021)	$ (200)	$ (21,561)	$ (21,683)

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Labor Expense
($000)

Salary Plan	2019 Average Headcount	2019 Base Salary	2019 Overtime and all Other Labor*	2019 TIA Labor Expense	2019 Total Salary & TIA Labor	2019 Labor Expense	2020 Labor Expense	2021 Labor Expense	2022 Labor Expense
Exempt	148	$ 15,835	$ 66	$ 1,668	$ 17,569				
Non-Exempt	17	$ 1,229	$ -	$ 126	$ 1,355				
Other-Part-time	1	$ 87	$ -	$ 9	$ 96				
Union / Non-Union Hourly	-	$ -	$ -	$ -	$ -				
Subtotal	166	$ 17,151	$ 66	$ 1,803	$ 19,020				
Co-ops / Interns	13	$ 423	$ -	$ -	$ 423				
Total	179	$ 17,574	$ 66	$ 1,803	$ 19,443	$12,341	$12,902	$13,061	$13,373

Note: Annual expense amounts are on an income statement basis and exclude balance sheet accounts.

Employee Headcount by Work Group

Department	June 30, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
Lines	33	33	33	33	33	33	33
Substation Construction & Maint	21	21	21	21	21	21	21
Substation Engineering	24	25	25	25	25	25	25
Project Management	6	7	7	7	7	7	7
System Operations	39	40	38	38	38	37	37
Energy Management Systems	7	9	10	9	9	9	9
Strategy & Planning	15	15	16	16	16	16	16
Policy & Tariffs	3	3	3	3	3	3	3
Reliability & Performance Standards	6	6	6	6	6	6	6
Administration	8	8	8	8	8	8	8
Interns	11	13	13	13	13	13	13
Total	173	180	180	179	179	178	178

Supplemental Contractors by Work Group

Work Group or Type of Work	May 31, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
Overhead Line Contractors	170	170	220	230	255	220	220
Line Clearing Contractors	102	102	102	102	102	102	102
Lines Climbing Inspections	8	12	12	12	12	12	12
Line Support	8	11	9	9	9	9	9
Construction and ROW Inspectors	13	17	21	24	27	19	19
Substation Engineering Design	58	71	71	71	71	71	71
Substation Construction	16	16	20	20	20	16	16
Substation Protection Techs	4	4	4	4	4	4	4
Substation Support	0	3	3	3	3	3	3
PMO Support	10	11	11	11	10	7	7
Total	389	417	473	486	513	463	463

Changes in the Overhead Lines Contractors and Construction and ROW Inspectors are driven by changes in capital spending over the business plan years

2017-2023 Headcount Totals & Changes

	Year-End						
Employees	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
TOTAL	**173**	**180**	**180**	**179**	**179**	**178**	**178**
Prior Plan		178	177	176	176	175	
Change From Prior Plan		2	3	3	3	3	

	2018 FC	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Supplemental Contractors	417	473	486	513	463	463
Prior Plan	389	458	471	482	432	
Change from Prior Plan	28	15	15	31	31	

Total Workforce (Employees Plus Supplemental Contractors)

Current Plan	597	653	665	692	641	641
Prior Plan	567	635	647	658	607	
Change from Prior Plan	30	18	18	34	34	

Plan Risks

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1. Revised regulations may materially increase investments and expenses.
2. Regional changes to the transmission grid topology, location and mix of generation resources, and other factors may result in power flows that drive the need for significant additional infrastructure investments.
3. System conditions (weather, external grid configuration and loop flows, generation status, etc.) may delay or alter outages required to complete construction.
4. Replacement power for [redacted] related to the announced retirements of the [redacted] may require additional projects and be eligible for incremental depancaking expense reimbursement
5. KYMEA sourcing of future transmission reservations may require additional projects and be eligible for incremental depancaking expense reimbursement.
6. Inflation may have a greater impact on vegetation management costs and overhead line construction than what has been assumed in the plan.

Operational Performance

Key Performance Indicators

KPI	2017 Year End	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Recordable Injury Incident Rate - Employees	0.67	0.00	0.69	0.69	0.69	0.69	0.69
Recordable Injury Incident Rate - Contractors	1.68	0.39	1.80	1.73	1.66	1.55	1.55
Days Away from work, Restriction, or Transfer - Employees	0.00	0.00	0.69	0.69	0.69	0.69	0.69
Annual SAIDI (minutes)	6.0	6.9	10.1	9.7	9.0	8.7	8.3
Cash Cost / MWh	$3.59	$4.32	$4.99	$5.80	$6.44	$7.29	$7.28
Cash Cost / Mile	$25,669	$30,728	$34,736	$39,823	$43,871	$49,216	$48,646

The 2018 Forecast for RIIR for both employees and contractors, DART for employees is the actual through June. SAIDI and Cash Cost / mile are based on the year-to-date actual through June 30, 2018 and forecast for July through December 2018.
The cash cost / MWh and the cash cost / mile are both the average of the five year period ending in that year.

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Energy Supply and Analysis
LG&E and KU Utilities
2019 Operating Plan

August 2018

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Plan Highlights

- Optimize the utilization of existing assets to provide reliable, low cost energy.
- Procure coal and gas necessary to cost-effectively operate generating plants.
- Maximize beneficial use of by-products to minimize pond closure and landfill development costs.
- Provide high quality analysis to enhance decision-making and ES&A risk management activities.
- Implement processes required to meet reliability standards.
- Improve analysis capability and knowledge about customer energy usage, DER, EVs, and storage to support DSM, ratemaking, legislative, customer service, and resource planning efforts.
- Target R&D activities to support major issues associated across the business.

Major Assumptions

- Analysis needed to support major company initiatives (KPSC filings) and strategic planning can be met by existing staff levels while absorbing headcount reductions due to retirements.
- Retirement risk is growing over the planning period but adequate time for training and development is forecasted to occur.
- Training for new employees will not require expenditures beyond recent historical experience for existing employees.
- No material change from historical non-labor expenses.

2017-2023 Annual O&M Expenses
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Expenses Only:							
Labor	$ 8,159	$ 8,068	$ 7,895	$ 7,964	$ 8,131	$ 8,314	$ 8,554
Dues	$ 4,628	$ 3,396	$ 3,362	$ 3,362	$ 3,362	$ 3,362	$ 3,362
Subscriptions	$ 419	$ 476	$ 531	$ 567	$ 571	$ 573	$ 574
Outside Services	$ 201	$ 205	$ 129	$ 141	$ 162	$ 162	$ 163
R&D Battery Storage Amortization	$ 457	$ 497	$ 496	$ 496	$ 496	$ 41	$ -
R&D Research Projects	$ 74	$ -	$ -	$ -	$ 144	$ 112	$ 215
Admin Fees - Reserve Sharing	$ 223	$ 228	$ 234	$ 240	$ 246	$ 253	$ 258
All Other Non-labor	$ 292	$ 316	$ 416	$ 416	$ 417	$ 416	$ 416
Total O&M Expense - Mgmt. View	**$ 14,453**	**$ 13,186**	**$ 13,063**	**$ 13,186**	**$ 13,529**	**$ 13,233**	**$ 13,542**
Plus:							
Base Gross Margin Items	$ 2,875	$ 3,763	$ 3,205	$ 3,142	$ 3,248	$ 3,397	$ 3,616
Mechanism Gross Margin Items	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total O&M Expense-GAAP View	**$ 17,328**	**$ 16,949**	**$ 16,268**	**$ 16,328**	**$ 16,777**	**$ 16,630**	**$ 17,158**

Note 1: Base Gross Margin Items exclude intercompany transmission expense.

Note 2: 2017 Actual O&M total contains restated Research & Development expenses.

Note 3: 2017 Actual O&M total contains restated TCRSG charged to Corporate in 2017.

2017-2023 Annual O&M Expenses
Non Labor – Dues
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
EPRI	$ 4,554	$ 3,290	$ 3,290	$ 3,290	$ 3,290	$ 3,290	$ 3,290
UofL Research Foundation	$ -	$ 50	$ -	$ -	$ -	$ -	$ -
American Coal Ash	$ 15	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17
Carbon Utilization Research Council	$ 15	$ 14	$ 14	$ 14	$ 14	$ 14	$ 14
Waterways Council	$ 11	$ 12	$ 12	$ 12	$ 12	$ 12	$ 12
National Coal Council	$ 8	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6
American Coal Council	$ 3	$ 5	$ 5	$ 5	$ 5	$ 5	$ 5
Other Miscellaneous	$ 22	$ 2	$ 18	$ 18	$ 18	$ 18	$ 18
Total Company Dues	$ 4,628	$ 3,396	$ 3,362	$ 3,362	$ 3,362	$ 3,362	$ 3,362

2017-2023 Annual O&M Expenses
Non Labor - Subscriptions
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
IHS Global	$ 145	$ 162	$ 187	$ 187	$ 187	$ 187	$ 187
PIRA	$ 80	$ 84	$ 83	$ 83	$ 83	$ 83	$ 83
Platts	$ 76	$ 61	$ 61	$ 62	$ 64	$ 66	$ 67
R&D - Bloomberg	$ 65	$ 77	$ 80	$ 80	$ 80	$ 80	$ 80
OATI	$ 16	$ 16	$ 16	$ 16	$ 16	$ 16	$ 16
Wood Mackenzie	$ -	$ 45	$ 30	$ 30	$ 30	$ 30	$ 30
R&D - IEEE	$ 18	$ 18	$ 20	$ 20	$ 20	$ 20	$ 20
Other Subscriptions	$ 19	$ 13	$ 54	$ 89	$ 91	$ 91	$ 91
Total Subscriptions	$ 419	$ 476	$ 531	$ 567	$ 571	$ 573	$ 574

2017-2023 Annual O&M Expenses
Non Labor – Outside Services
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
R&D Engineering Studies	$ 58	$ 75	$ 50	$ 50	$ 50	$ 50	$ 50
R&D UofL Research	$ 50	$ -	$ -	$ -	$ -	$ -	$ -
Consumer Behavior Study	$ -	$ 65	$ -	$ -	$ -	$ -	$ -
Weir Services	$ -	$ 25	$ 42	$ 42	$ 42	$ 42	$ 42
Cambridge Energy Research	$ -	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8
Contract Employee	$ 51	$ 8	$ 13	$ 13	$ 13	$ 13	$ 13
Other Outside Services	$ 42	$ 24	$ 16	$ 28	$ 49	$ 49	$ 50
Total Outside Services	$ 201	$ 205	$ 129	$ 141	$ 162	$ 162	$ 163

2017-2023 Annual O&M Expenses
Non Labor – Research & Development
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Battery Storage Amort.	$ 457	$ 497	$ 496	$ 496	$ 496	$ 41	$ -
UofL EV-STS Project	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other R&D Projects	$ 74	$ -	$ -	$ -	$ 144	$ 112	$ 215
Total R&D	$ 531	$ 497	$ 496	$ 496	$ 640	$ 153	$ 215

2017-2023 Annual Expenses
Base Gross Margin Items
($000)

CONFIDENTIAL INFORMATION REDACTED

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
[redacted] Cost for Serving KU	$ 2,921	$ 2,965	$ 3,002	$ 2,973	$ 2,984	$ 3,005	$ 3,029
RTO Cost - NL	$ (5)	$ 5	$ 9	$ 5	$ 5	$ 5	$ 1
RTO Cost - OSS	$ (49)	$ 762	$ 153	$ 150	$ 244	$ 374	$ 583
3rd Party XM - NL	$ 3	$ 20	$ 41	$ 14	$ 15	$ 13	$ 3
3rd Party XM - OSS	$ 5	$ 11	$ -	$ -	$ -	$ -	$ -
Total	$ 2,875	$ 3,763	$ 3,205	$ 3,142	$ 3,248	$ 3,397	$ 3,616

Note 1: Base Gross Margin Items exclude intercompany transmission expense.

Note 2: Industrial Coal Services costs are included in 456 revenue starting in 2017.

O&M Annual Expense Reconciliation
($000)

	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
2018 Expectation	$ 13,063	$ 13,186	$ 13,529	$ 13,233	$ 13,542
Drivers:					
Power Supply Retirements-Not Backfilled	$ (211)	$ (327)	$ (335)	$ (344)	$ (354)
Gen. Planning - Adjust Retirement Timing	$ 75	$ -	$ -	$ -	$ -
Eliminate Non-labor Gap	$ 136	$ 184	$ 207	$ 207	$ 207
Expectation Cost Reduction	$ -	$ 157	$ -	$ -	$ -
Research & Development Project Expenses	$ -	$ -	$ 145	$ 112	$ 215
Labor Adjustments - Sales Analysis	$ -	$ 36	$ 37	$ 38	$ 39
Lower Non-labor Inflation than 18BP	$ -	$ -	$ -	$ -	$ (43)
All Other	$ -	$ (50)	$ (54)	$ (13)	$ (64)
Current Plan - Mgt. View	$ 13,063	$ 13,186	$ 13,529	$ 13,233	$ 13,542

2017-2023 Capital Expenditures ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Total Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2017 Plan	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Change	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Labor Expense
($000)

Salary Plan	2019 Average Headcount	2019 Base Salary	2019 Overtime and all Other Labor*	2019 TIA Labor Expense	2019 Total Salary & TIA Labor	2019 Labor Expense	2020 Labor Expense	2021 Labor Expense	2022 Labor Expense	2023 Labor Expense
Exempt	55	$ 5,781	$ 52	$ 697	$ 6,530	$ 7,480				
Non-Exempt	5	$ 261	$ -	$ 31	$ 292	$ 335				
Part-time	1	$ 39		$ 5	$ 44	$ 44				
Union	-	$ -	$ -	$ -	$ -	$ -				
Non-Union Hourly	-	$ -	$ -	$ -	$ -	$ -				
Subtotal	61	$ 6,081	$ 52	$ 733	$ 6,866	$ 7,859				
Co-ops / Interns	2	$ 36	$ -	$ -	$ 36	$ 36				
Total	63	$ 6,117	$ 52	$ 733	$ 6,902	$ 7,895	$ 7,964	$ 8,131	$ 8,314	$ 8,554

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Employee Headcount by Work Group

Work Group or Major Dept.	June 30, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
Power Supply	23	23	22	22	22	22	22
Dir. Plan & Analysis	2	2	2	2	2	2	2
Generation Planning	9	9	8	8	8	8	8
Sales Analysis	6	6	6	6	6	6	6
V.P. Energy Supply	2	2	2	2	2	2	2
Fuels Management	6	6	6	6	6	6	6
Fuels & By Products	10	10	10	10	10	10	10
Research & Develop.	4	4	4	4	4	4	4
Interns	4	2	2	2	2	2	2
Total	66	64	62	62	62	62	62

2017-2023 Headcount Totals & Changes

	Year-End						
Employees	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
TOTAL From Page 14	65	63	62	62	62	62	62
Prior Plan		65	63	63	63	63	63
Change From Prior Plan		(2)	(1)	(1)	(1)	(1)	(1)

	2018 FC	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Supplemental Contractors (Page 15)	0	0	0	0	0	0
Prior Plan	0	0	0	0	0	0
Change from Prior Plan	0	0	0	0	0	0

Total Workforce (Employees Plus Supplemental Contractors)

Current Plan	63	62	62	62	62	62
Prior Plan	65	63	63	63	63	63
Variance	(2)	(1)	(1)	(1)	(1)	(1)

Note 1: 2017 Actual has been restated to include R&D.

Note 2: Includes Interns.

Plan Risks

- OSS margin risk is minimal due lower electricity prices and KY sharing mechanism.
- Workforce transition due to retirements.
- Unanticipated major project that would require material outside services (low risk).

Corporate Cost Center
LG&E and KU Utilities
2019 Operating Plan

August 2018

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Major Assumptions

- Benefits for 2019 based on 3,672 full-time, 111 co-ops/interns, and 21 part-time regular employees (as of 12/31/19)
  — Full-time actual headcount at June 30, 2018 is 3,439.
- The projection for medical was based upon the calculation provided by Mercer and adjusted for incremental headcount, and adjusted 4% each year thereafter.
- Amortization of regulatory assets will continue through plan periods based on KPSC orders.
- Incentive expenses based on:
  — Safety, customer service, cost control, reliability goals
  — Individual effectiveness and team goals
- IMEA/IMPA portion included in Corporate is the credit that covers the same burden types that hit Corporate. The balance of IMEA/IMPA reimbursements are included within Power Production.

Major Assumptions

- Pension Costs
  - The mortality assumption reflects the RP-2014 gender specific healthy employee and healthy annuitant mortality tables with collar and factor adjustments and applying MP-2017 mortality improvements from 2006 on a generational basis.
  - 15 year amortization period used for KPSC-jurisdictional accounting/ratemaking. Double corridor used for Virginia, FERC and LKS charges to LKC.
  - Discount rate is assumed to be 4.2% for the non-union plan and 4.15% for the union plan. These are 50bps higher than discount rates at 12/31/17 based on changes in corporate bond rates through April 2018.
  - EROA is assumed to be 7%
  - Lump sum take rate is assumed to be 50%
  - Service cost is assumed to decrease 4.00% annually for the Non-Union plan and decrease 10.00% annually for the Union plan, except that the Union service cost includes an assumed offsetting increase of 7.5% every three years (i.e., the increases for 2021-2023 are assumed to be reflected at January 1, 2021) consistent with the impact of the plan changes resulting from the union negotiations in 2017.

2017-2023 Annual O&M Expenses ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Expenses Only:							
Labor Burdens	$ 89,877	$ 89,422	$ 90,093	$ 92,983	$ 95,623	$ 98,036	$ 100,531
Amortization of Regulatory Assets	$ 14,654	$ 16,285	$ 13,165	$ 11,522	$ 7,846	$ 4,299	$ 4,299
A&G Transferred Credit	$ (10,592)	$ (11,421)	$ (11,835)	$ (12,243)	$ (12,659)	$ (13,133)	$ (13,470)
IMEA/IMPA Billings	$ (4,354)	$ (4,107)	$ (3,800)	$ (3,955)	$ (4,060)	$ (4,159)	$ (4,399)
Life Insurance	$ (1,966)	$ (1,621)	$ (1,614)	$ (1,646)	$ (1,679)	$ (1,713)	$ (1,748)
PPL Direct	$ 1,830	$ 1,801	$ 1,655	$ 1,447	$ 1,828	$ 1,553	$ 1,599
All Other Non-labor	$ 1,609	$ 1,900	$ 867	$ 865	$ 673	$ 338	$ 310
Total O&M Expense - GAAP View	**$ 91,058**	**$ 92,259**	**$ 88,531**	**$ 88,973**	**$ 87,571**	**$ 85,221**	**$ 87,121**
Plus:							
Pension NonService Cost	$ 5,767	$ (1,228)	$ (6,552)	$ (8,291)	$ (9,698)	$ (11,243)	$ (13,771)
Total O&M Expense-Mgmt View	**$ 96,825**	**$ 91,031**	**$ 81,978**	**$ 80,682**	**$ 77,873**	**$ 73,978**	**$ 73,350**

2017-2023 Annual O&M Expenses
Corporate Labor Burdens
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Corporate Labor Burdens							
Pension (Service Cost)	$ 22,672	$ 17,824	$ 15,263	$ 14,883	$ 14,668	$ 14,172	$ 13,618
Medical/Dental	$ 22,258	$ 28,898	$ 31,219	$ 32,617	$ 33,892	$ 35,218	$ 36,596
Payroll Taxes	$ 19,019	$ 21,393	$ 20,781	$ 21,385	$ 22,026	$ 22,687	$ 23,367
401k Total *(matching & drop-in)*	$ 13,104	$ 13,585	$ 14,085	$ 14,840	$ 15,608	$ 16,432	$ 17,316
Post Retirement	$ 4,969	$ 3,221	$ 2,706	$ 2,578	$ 2,518	$ 2,379	$ 2,239
Other Burdens:							
Group Life Insurance	$ 987	$ 1,081	$ 1,162	$ 1,501	$ 1,546	$ 1,592	$ 1,640
Long Term Disability	$ 1,051	$ 1,085	$ 1,252	$ 1,447	$ 1,490	$ 1,535	$ 1,581
Worker's Compensation	$ 2,065	$ 460	$ 1,400	$ 1,474	$ 1,547	$ 1,625	$ 1,706
Post Employment	$ 801	$ (1,037)	$ -	$ -	$ -	$ -	$ -
Other *(Wellness,PBGC,TWR/Mercer fees)*	$ 2,951	$ 2,913	$ 2,225	$ 2,260	$ 2,328	$ 2,397	$ 2,469
Total Other Burdens	$ 7,855	$ 4,502	$ 6,039	$ 6,681	$ 6,910	$ 7,149	$ 7,396
Total O&M Expense - Mgmt. View	**$ 89,877**	**$ 89,422**	**$ 90,093**	**$ 92,983**	**$ 95,623**	**$ 98,036**	**$ 100,531**
Plus:							
Pension NonService Cost	$ 5,767	$ (1,228)	$ (6,552)	$ (8,660)	$ (9,554)	$ (11,028)	$ (13,419)
Total O&M Expense-GAAP View	**$ 95,644**	**$ 88,195**	**$ 83,541**	**$ 84,323**	**$ 86,069**	**$ 87,008**	**$ 87,112**

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LG&E KU PPL companies

O&M Annual Expense Reconciliation
($000)

	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
2018 Plan/Expectation	$98,710	$93,427	$90,081	$90,122	$90,073
Drivers:					
Pension Service Cost	$ (2,923)	$ (2,818)	$ (3,094)	$ (3,305)	$ (2,257)
Payroll Taxes	$ (1,473)	$ (1,537)	$ (1,582)	$ (1,630)	$ (1,679)
Post Retirement	$ (514)	$ (520)	$ (555)	$ (612)	$ (750)
Post Employment	$ (242)	$ (242)	$ (242)	$ (242)	$ (242)
Medical/Dental	$ (488)	$ (369)	$ (421)	$ (475)	$ (532)
Other labor burdens	$ (797)	$ (336)	$ (332)	$ (326)	$ (317)
Reg Asset Recalc	$ (3,733)	$ (182)	$ 3,546	$ 913	$ 1,423
Other	$ (9)	$ 1,549	$ 170	$ 776	$ 1,403
Current Plan - GAAP View	$88,531	$88,973	$87,571	$85,221	$87,121

Plan Risks

- The largest plan risk is pension expense. Discount rates assumed are 50bps higher than discount rates at 12/31/17 based on changes in corporate bond rates through April 2018. These rates have changed since then and will fluctuate over time.
- The second largest risk is medical expense, but it is partially mitigated by the 4/4/50 sharing relationship.

CFO Excluding IT
LG&E and KU Utilities
2019 Operating Plan

August 2018

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Plan Highlights

- CFO group is designed to meet the overall objectives of the Company in the most cost effective manner possible.
  - Functions include accounting, financial reporting, regulatory reporting, tax, payroll, financing, cash management, investor relations, forecasting & budgeting, financial planning & analysis, insurance, pensions, rates, state regulatory affairs, audit services, SOX compliance and supply chain.
- Headcount, excluding interns, will remain flat compared to the 2018BP throughout the plan.
  - Labor represents 46% of the CFO 2019BP O&M expenses.
- Insurance represents 39% of the CFO 2019BP O&M expenses.
- Bank Fees and Audit Fees each represent an additional 4% of O&M.

Major Assumptions

- Projected insurance premiums are based on feedback from brokers and increase for amount of property placed in service.
  - A larger property increase in 2020 is assumed once the three year rate freeze expires.
  - The membership credits offered by FM Global and AEGIS are not assumed to continue beyond 2018 renewal.
- Several new bonds related to pond and landfill closure will be required (included in insurance budget).
- Bank Fees, excluding rating agency fees, are projected to increase at approximately 1.4% annually based on recent experience.

Major Assumptions

- Audit Fees
  - Audit fees through 2018 are based on negotiated fees with firms and prior costs of predecessor consents. Audit fees for financial statements beyond 2018 are based on estimates provided by the external auditors.
  - Benefit plan audits will be re-bid in 2018 and are expected to increase at rates consistent with prior years.
  - Expected incremental work for auditor consent letters for financings will be amortized over the life of the financing.
  - No other incremental work (e.g., system post-implementation audits) is assumed.

Major Assumptions

- State Regulation & Rates
  - Filing of base rate cases for LG&E and KU in Kentucky.
  - Filing of base rate cases for KU in Virginia.
  - Annual revision of the formula rates for FERC wholesale municipal and OATT customers.
  - Filing of Integrated Resource Plan.
    - KY – 2018 & 2021
    - VA – Annual
  - Filing of new ECR Plan to address ELG Regulations – late 2019.

2017-2023 Annual O&M Expenses ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Expenses Only:							
Labor	$20,314	$20,185	$20,601	$21,309	$21,833	$22,326	$22,964
Insurance	$15,774	$15,723	$17,596	$18,816	$19,746	$20,159	$20,355
Bank Fees	$ 1,465	$ 1,691	$ 1,721	$ 1,752	$ 1,785	$ 1,818	$ 1,853
Audit Fees	$ 1,669	$ 1,594	$ 1,769	$ 1,770	$ 1,771	$ 1,974	$ 1,975
Training, Travel & Meals	$ 377	$ 450	$ 529	$ 523	$ 525	$ 527	$ 532
Outside Services	$ 103	$ 237	$ 231	$ 184	$ 232	$ 160	$ 167
All Other Non-labor	$ 2,146	$ 2,589	$ 2,476	$ 2,625	$ 2,472	$ 2,639	$ 2,528
Total O&M Expense - Mgmt. View	**$41,848**	**$42,469**	**$44,923**	**$46,979**	**$48,364**	**$49,603**	**$50,374**

2017-2023 Annual O&M Expenses
Insurance
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Insurance Expenses:							
Property Insurance	$ 9,079	$ 8,914	$ 9,962	$ 11,105	$ 11,978	$ 12,363	$ 12,559
Excess Liability Insurance	$ 3,214	$ 3,199	$ 3,397	$ 3,396	$ 3,396	$ 3,396	$ 3,396
Pollution Legal Liability	$ 1,202	$ 1,220	$ 1,345	$ 1,345	$ 1,345	$ 1,345	$ 1,345
Directors and Officers Insurance	$ 512	$ 476	$ 519	$ 519	$ 519	$ 519	$ 519
Closure Bonds	$ 202	$ 366	$ 818	$ 877	$ 921	$ 938	$ 938
Underwriters Safety & Claims	$ 393	$ 373	$ 385	$ 395	$ 395	$ 395	$ 395
Cyber Insurance	$ 283	$ 279	$ 331	$ 333	$ 343	$ 354	$ 354
All Other Insurance	$ 889	$ 896	$ 839	$ 846	$ 849	$ 849	$ 849
Total Insurance	$ 15,774	$ 15,723	$ 17,596	$ 18,816	$ 19,746	$ 20,159	$ 20,355

2017-2023 Annual O&M Expenses
Bank Fees
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Bank Fees:							
Rating Agency Fees	$ 457	$ 606	$ 748	$ 766	$ 785	$ 804	$ 825
Bank Service Fees	$ 672	$ 668	$ 586	$ 599	$ 613	$ 627	$ 641
Trustee Fees	$ 105	$ 180	$ 199	$ 199	$ 199	$ 199	$ 199
NYSE Fees	$ 162	$ 156	$ 142	$ 142	$ 142	$ 142	$ 142
LC Fees	$ 69	$ 82	$ 46	$ 46	$ 46	$ 46	$ 46
Total Bank Fees	$ 1,465	$ 1,691	$ 1,721	$ 1,752	$ 1,785	$ 1,818	$ 1,853

O&M Annual Expense Reconciliation ($000)

	2019 Plan	2020 Plan		2021 Plan	2022 Plan	2023 Plan
2018 Plan/Expectation	$44,571	$45,518		$46,786	$47,870	$48,679
Drivers:						
Labor	$ (206)	$ (231)		$ (208)	$ (219)	$ (258)
Insurance	$ 180	$ 773		$ 1,428	$ 1,528	$ 1,537
Bank Fees	$ 72	$ 52		$ 37	$ 23	$ 40
All Other Non-Labor	$ 306	$ 867	*	$ 321	$ 401	$ 376
Current Plan - Mgt. View	$44,923	$46,979		$48,364	$49,603	$50,374

**2020 Includes Expectation Reduction*

2017-2023 Capital Expenditures
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Lexington Forklift	$ 281	$ -	$ -	$ -	$ -	$ -	$ -
Auburndale Pole Racks	$ 197	$ -	$ -	$ -	$ -	$ -	$ -
Danville Pole Racks	$ -	$ 170	$ -	$ -	$ -	$ -	$ -
Lexington Tran Pole Yard	$ -	$ -	$ 250	$ -	$ -	$ -	$ -
Lexington Tran Pole Rack	$ -	$ -	$ 200	$ -	$ -	$ -	$ -
Elizabethtown Pole Racks	$ -	$ -	$ 150	$ -	$ -	$ -	$ -
Paris Pole Yard	$ -	$ -	$ -	$ 150	$ -	$ -	$ -
Winchester Pole Yard	$ -	$ -	$ -	$ 150	$ -	$ -	$ -
All Other	$ 1,390	$ 1,334	$ 924	$ 520	$ 820	$ 820	$ 820
Total Capital	$ 1,868	$ 1,504	$ 1,524	$ 820	$ 820	$ 820	$ 820
2018 Plan		$ 1,712	$ 873	$ 450	$ 1,000	$ -	$ -
Change		$ (208)	$ 651	$ 370	$ (180)	$ 820	$ 820

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LG&E KU
PPL companies

Labor Expense

Salary Plan	Average Headcount	Base Salary	Overtime and all Other Labor*	TIA Labor Expense	Total Salary & TIA Labor	2019 Labor Expense	2020 Labor Expense	2021 Labor Expense	2022 Labor Expense	2023 Labor Expense
	2019									
Exempt	173	$ 17,838	$ -	$ 1,803	$ 19,642					
Non-Exempt	33	$ 1,856	$ -	$ 176	$ 2,032					
Non-Union Hourly	4	$ 249	$ -	$ 25	$ 274					
Subtotal	210	$ 19,943	$ -	$ 2,005	$ 21,948					
Co-ops / Interns	14	$ 392	$ -	$ 45	$ -					
Total	224	$ 20,335	$ -	$ 2,050	$ 21,948	$ 20,601	$ 21,309	$ 21,833	$ 22,326	$ 22,964

Note: Annual expense amounts are on an income statement basis and exclude balance sheet accounts.

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Employee Headcount by Work Group

Work Group or Major Dept.	May 31, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
CFO	2	2	2	2	2	2	2
Audit Services	14	14	14	14	14	14	14
Controller	68	68	69	69	69	69	69
Treasurer	51	51	51	51	51	51	51
State Reg & Rates	15	16	16	16	16	16	16
Supply Chain	54	58	58	58	58	58	58
Interns	16	14	14	14	14	14	14
Total	220	223	224	224	224	224	224

Supplemental Contractors by Work Group

Work Group or Type of Work	May 31, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
Supply Chain	26	26	27	27	27	27	27
Total	26	26	27	27	27	27	27

2017-2023 Headcount Totals & Changes

	Year-End						
	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Employees							
TOTAL From Page 13	224	223	224	224	224	224	224
Prior Plan		222	222	222	222	222	
Change From Prior Plan		1	2	2	2	2	

	2018 FC	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Supplemental Contractors Page 14	26	27	27	27	27	27
Prior Plan	23	23	23	23	23	23
Change from Prior Plan	3	4	4	4	4	4

Total Workforce (Employees Plus Supplemental Contractors)

Current Plan	249	251	251	251	251	251
Prior Plan	245	245	245	245	245	23
Change from Prior Plan	4	6	6	6	6	228

2018 includes 1 transfer from IT; 2019 includes an added manager position

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Plan Risks

- The continued movement of software to hosted environments creates increases in O&M costs and increases the risk of functionality gaps.
- An increased focus on IT security and verification of vendor compliance with Company security requirements may require incremental resources.
- Technical support for in-house software, such as Oracle, is not meeting business expectations.
- Integration of primary system changes within planning window and their impact on existing processes (PowerPlan, Volts replacement, Oracle, etc.).

Plan Risks

- Maintaining flat staffing levels, along with less experienced resources, will
  - Impact the ability to resource special projects and major system upgrades and may prompt the need for additional external resources.
  - Impact the ability to develop and take advantage of new technologies, such as RPA.
- Higher level of employee retirements during plan period place greater emphasis on knowledge transfer and effective timing of staffing changes.
- The level of rate increases for insurance premiums are at historically low levels and creates a level of risk regarding future premiums.

Information Technologies
LG&E and KU Utilities
2019 Operating Plan

September 2018 – Updated to reflect KPSC AMS ruling

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Plan Highlights

- The 2019 Information Technology O&M Budget submitted for the 2019 Business Plan is $64.95 million
- Hardware/software maintenance under contract or additions included in the 2019 BP account for 36% to 38% of the Information Technology budget over the 5 year plan period.
- Roughly 52% of the 5 year capital plan (approximately $120M) represents 19 major projects (including $40M for Enterprise GIS, $14M for Financial & Supply Chain systems, $15M for Tech Refresh, and $11M for Infrastructure Telecommunications Network).
- The 2019 Information Technology Capital budget submitted for the 2019 Business Plan is $43 million and is $600k higher than the 2018 Business Plan.

Major Assumptions

- Safety & Regulatory
  - *Increased regulatory scrutiny at FERC, NERC and SERC as it relates to Critical Infrastructure Protection (CIP) and cybersecurity will drive the need for increased spending for both labor and information technology solutions to meet compliance and information protection requirements.*
  - *Increased emphasis on SOX regulations has caused incremental work.*

Major Assumptions

- Business Reliance on Technology
  - *Business reliance on information technology services to conduct day to day operations continues to expand. More business processes are moving towards automation.*
  - *To address the need for skill set flexibility and scalability in the IT Application Development and Support area a co-source partner is being identified with the expectation that a contract will be in place in 4th quarter 2018.*
  - *This trend means the reliability and availability of information technology services is critically important to the business. There is little tolerance for almost any kind of system outage. This leads to an increased focus on planned and automated testing activities for all major system changes.*
  - *Increased reliance on technology is leading to increased storage, maintenance and support costs which are reflected in the plan. We continue to look for ways to mitigate these increases through adoption of new infrastructure technologies that offer lower support costs.*

Major Assumptions

- Cybersecurity Threats
  - *Cybersecurity threats and data protection issues continue to increase. These threats are becoming even more sophisticated and difficult to overcome. Third party security assessments and recommendations for new protection measures will likely initiate changes to the plan.*
- Customer Experience
  - *Implementation of the Advanced Metering Systems will occur during this business plan period.*
  - *As our primary interface with our customers, maintaining the CCS system is critical to meet customer and business expectations.*
  - *Expansion of green energy technologies will require enhancements to the CCS system.*

Major Assumptions

- Advances in New Technologies
  - *Continuing to leverage mobile technologies will be a major differentiator for productivity and customer satisfaction.*
  - *Robotic Process Automation has potential to provide business benefit. Proofs of concepts and identification of use-cases will determine priority for implementation.*
  - *Plans include working closely with the business to determine which of these technologies can deliver the greatest benefit.*
  - *The use of advanced data analytics has the potential to optimize operations; funding has been included in the current business plan. The need for data analysis positions in IT and the business areas is recognized and has been included in the plan.*

2017-2023 Annual O&M Expenses ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Expenses Only:							
Labor	$ 22,995	$ 26,009	$ 29,424	$ 30,615	$ 31,484	$ 32,373	$ 33,333
Supplemental Contractors	$ 2,429	$ 3,877	$ 4,020	$ 4,175	$ 4,250	$ 4,350	$ 4,434
HW/SW Maintenance	$ 20,069	$ 21,093	$ 23,413	$ 25,532	$ 26,896	$ 28,434	$ 29,969
O/S Services	$ 1,303	$ 2,086	$ 2,508	$ 4,936	$ 4,737	$ 4,763	$ 4,802
Telecom	$ 2,662	$ 2,613	$ 2,910	$ 2,915	$ 2,922	$ 2,928	$ 2,932
Training, Travel, & Meals	$ 823	$ 1,186	$ 1,387	$ 1,375	$ 1,403	$ 1,404	$ 1,413
Vehicles/Equipment	$ 241	$ 290	$ 297	$ 302	$ 308	$ 312	$ 315
All Other Non-labor	$ 826	$ 769	$ 768	$ 773	$ 777	$ 783	$ 788
Total O&M Expense - Mgmt. View	**$ 51,347**	**$ 57,923**	**$ 64,726**	**$ 70,622**	**$ 72,777**	**$ 75,346**	**$ 77,986**

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Labor Expense

Salary Plan	2019 Average Headcount	2019 Base Salary	2019 Overtime and all Other Labor*	2019 TIA Labor Expense	2019 Total Salary & TIA Labor	2019 Labor Expense	2020 Labor Expense	2021 Labor Expense	2022 Labor Expense	2023 Labor Expense
Exempt	265	$ 30,280	$ -	$ 3,089	$ 33,369					
Non-Exempt	36	$ 2,394	$ 387	$ 247	$ 3,028					
Union / Non-Union Hourly	11	$ 929	$ 157	$ 84	$ 1,170					
Subtotal	312	$ 33,602	$ 545	$ 3,421	$ 37,568					
Co-ops / Interns	13	$ 303	$ -	$ 34	$ 337					
Total	325	$ 33,905	$ 545	$ 3,455	$ 37,905	$ 29,424	$ 30,615	$ 31,484	$ 32,373	$ 33,333

Note: Annual expense amounts are on an income statement basis and exclude balance sheet accounts.

2017-2023 Annual O&M Expenses
Supplemental Contractors
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
SUPPLEMENTAL CONTRACTORS							
Dev & Support	$ 1,865	$ 2,379	$ 2,730	$ 2,883	$ 2,925	$ 2,988	$ 3,035
Infrastructure & Ops	$ 531	$ 1,343	$ 1,141	$ 1,142	$ 1,175	$ 1,212	$ 1,249
Testing Resources	$ 33	$ 41	$ -	$ -	$ -	$ -	$ -
Telecom	$ -	$ 115	$ 150	$ 150	$ 150	$ 150	$ 150
	$ 2,429	$ 3,877	$ 4,020	$ 4,175	$ 4,250	$ 4,350	$ 4,434

2017-2023 Annual O&M Expenses
Hardware/Software Maintenance
($000)

Line of Business	Primary Systems/Vendors	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
IT Company	Microsoft, Oracle Databases	$ 5,200	$ 4,796	$ 5,340	$ 6,065	$ 6,526	$ 6,839	$ 7,426
IT Infrastructure	Prosys Info Systems, World Wide Tech	$ 4,432	$ 4,883	$ 5,409	$ 6,011	$ 6,265	$ 6,545	$ 6,918
Distribution	GE, SPL/NMS/DMS, ABB, ARM, ESRI	$ 2,372	$ 2,676	$ 3,074	$ 3,175	$ 3,287	$ 3,427	$ 3,578
Customer Services	SAP	$ 2,467	$ 2,464	$ 2,635	$ 2,749	$ 3,009	$ 3,276	$ 3,416
IT Security	NERC(Crisp), IBM, Enhanced Threat	$ 1,404	$ 1,515	$ 1,761	$ 1,907	$ 1,989	$ 2,172	$ 2,203
Finance	Oracle, Powerplan	$ 1,349	$ 1,437	$ 1,643	$ 1,885	$ 1,960	$ 2,039	$ 2,120
Energy Supply & Analysis	nMarket, Aligne Fuels	$ 725	$ 710	$ 734	$ 764	$ 794	$ 826	$ 859
Transmission	Cascade,PI Systems	$ 421	$ 664	$ 766	$ 806	$ 822	$ 854	$ 888
Power Production	Maximo	$ 695	$ 575	$ 607	$ 666	$ 731	$ 801	$ 879
Generation Services	LOTO (Eclipse)	$ 206	$ 333	$ 415	$ 432	$ 450	$ 469	$ 489
Human Resources	Peoplesoft	$ 303	$ 313	$ 324	$ 339	$ 353	$ 367	$ 381
AMS	MAM	$ 8	$ 105	$ 171	$ 169	$ 142	$ 141	$ 141
General Counsel	Acquia Enterprise Services	$ 78	$ 78	$ 77	$ 77	$ 77	$ 77	$ 77
Sales Tax		$ 408	$ 541	$ 458	$ 488	$ 493	$ 601	$ 593
Grand Total		$ 20,069	$ 21,093	$ 23,413	$ 25,532	$ 26,896	$ 28,434	$ 29,969

2017-2023 Annual O&M Expenses Outside Services ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
PROFESSIONAL SERVICES							
HW/SW Maintenance	$ 259	$ 332	$ 530	$ 550	$ 573	$ 597	$ 621
IT Security	$ 36	$ 182	$ 209	$ 194	$ 219	$ 222	$ 224
Telecom	$ 0	$ 0	$ 0	$ 50	$ 50	$ 0	$ 0
Infrastructure & Ops	$ 0	$ 165	$ 38	$ 109	$ 39	$ 110	$ 110
Dev & Support	$ 121	$ 536	$ 545	$ 821	$ 522	$ 522	$ 522
	$ 416	$ 1,216	$ 1,321	$ 1,723	$ 1,402	$ 1,451	$ 1,478
OTHER CONTRACTOR							
Testing Resources	$ 256	$ 315	$ 480	$ 480	$ 480	$ 480	$ 480
Telecom	$ 240	$ 216	$ 246	$ 253	$ 325	$ 352	$ 364
Dev & Support*	$ 339	$ 296	$ 403	$ 2,422	$ 2,472	$ 2,422	$ 2,422
Infrastructure & Ops	$ 52	$ 44	$ 58	$ 58	$ 58	$ 58	$ 58
	$ 887	$ 870	$ 1,187	$ 3,213	$ 3,335	$ 3,312	$ 3,324
TOTAL OUTSIDE SERVICES	$ 1,303	$ 2,086	$ 2,508	$ 4,936	$ 4,737	$ 4,763	$ 4,802

* Includes approximately $2 million in 2020-2023 in data coversion for GIS

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2019 O&M Expenses
Telecom - Wireless Expenses
($000)

Exp Type Description	Extended Description (all for sites not on our own network)	2019
DPS-LD	For Voice Network - Long Distance, 800 number usage, WEBEX, etc	$ 180
DPS-1FB I	For Voice Network - Business phone lines to subs, smal offices, storerooms, etc	$ 165
DPS-LSELINE I	For Voice Network - Leased lines between locations	$ 18
DPS-TRUNKS I	For Voice Network - Trunks into major campus locations	$ 503
LMR-LSELINE I	For Radio Network - leased liones to repeater locations	$ 48
SNAT 1FBDATA I	For Data Network - Alarm, modem, meter backp SCADA lines	$ 39
SNAT-DSL I	For Data Network - For backup/test/secured access to Internet	$ 6
SNAT-INTERNET I	For Data Network - Main Internet connections that are not prepaid	$ 66
SNAT-ISDN I	For Data Network - 21st Century Connection for Call Center	$ 21
SNAT-LSELINE I	For Data Network - leased lines to subs, business offices, storerooms not on network	$ 1,263
		$ 2,310
	Cellular and Paging	$ 555
	Lease, Rental & Other	$ 45
Total Telecom		$ 2,910

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LG&E KU
PPL companies

O&M Annual Expense Reconciliation ($000)

	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
2018 Plan/Expectation	$ 62,134	$ 64,850	$ 66,039	$ 66,956	$ 71,307
Drivers:					
IT HW/SW Maintenance	$ 1,087	$ 1,705	$ 2,124	$ 3,822	$ 2,094
Outside Services	$ (120)	$ 2,477	$ 2,987	$ 2,909	$ 2,912
Supplemental Contractors	$ 1,499	$ 1,625	$ 1,669	$ 1,720	$ 1,777
Telecom	$ (166)	$ (167)	$ (160)	$ (160)	$ (187)
Training & Travel	$ 131	$ 104	$ 117	$ 106	$ 102
Labor	$ 199	$ 78	$ 60	$ 56	$ 47
All Other	$ (37)	$ (49)	$ (60)	$ (63)	$ (65)
Current Plan - Mgt. View	$ 64,726	$ 70,622	$ 72,777	$ 75,346	$ 77,986

2017-2023 Capital Expenditures ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Enterprise GIS	$ 1,487	$ 1,221	$ 7,697	$ 12,400	$ 8,347	$ 7,797	$ 3,829
Tech Refresh Desk/Laptop	$ 2,237	$ 2,600	$ 2,685	$ 2,985	$ 2,985	$ 2,985	$ 2,986
SAP CRM/ECC Upgrade	$ 8,455						
SAP S4/HANA Upgrade					$ 2,986	$ 6,958	
Oracle Financials Upgrade				$ 3,089	$ 3,885		
OTN Extension		$ 1,200	$ 1,386	$ 864	$ 739	$ 739	$ 1,903
NorthEast KY Transport Buildout	$ 22	$ 7	$ 10	$ 136	$ 1,805	$ 1,805	$ 1,805
NMS - Network Mgmt System Upgrd	$ 1,203	$ 1				$ 990	$ 1,239
WMS - Work Mgmt System Upgrd	$ 193	$ 2,350					$ 1,973
EMC TLA Renewal				$ 4,500			
Microsoft EA/True-up	$ 512	$ 419	$ 535	$ 650	$ 650	$ 650	$ 750
PowerPlan Upgrade			$ 1,240	$ 1,592			$ 1,242
Computing Infrastructure Upgrade			$ 1,002	$ 582	$ 842	$ 601	$ 861
Data Analytics			$ 825	$ 700	$ 700	$ 700	$ 700
Access Switch Rotation	$ 525	$ 510	$ 493	$ 493	$ 493	$ 494	$ 494
Time and Labor Upgrade			$ 732	$ 1,556	$ 737		
Windows 10 Upgrade	$ 199	$ 567	$ 519	$ 394	$ 394	$ 395	$ 395
Corporate Robotic Process Automation			$ 500	$ 500	$ 494	$ 495	$ 495
MFD Growth and Refresh	$ 72	$ 21	$ 40	$ 900	$ 600		$ 40
Ayava IVR Upgrade					$ 595	$ 993	
All Other Projects	$ 27,774	$ 34,265	$ 31,234	$ 26,547	$ 20,077	$ 18,795	$ 17,109
Total Capital	**$ 42,679**	**$ 43,161**	**$ 48,897**	**$ 57,889**	**$ 45,734**	**$ 43,404**	**$ 35,820**
2018 Plan		$ 42,764	$ 35,087	$ 44,892	$ 43,803	$ 28,632	$ 40,045

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Employee Headcount by Work Group

Work Group or Major Dept.	June 30, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
CIO	2	2	6	6	6	6	6
IT Infrastructure & Ops	146	161	158	158	158	158	158
IT Dev & Support	75	85	78	78	78	78	78
IT Business Services	41	44	45	45	45	45	45
IT Security	19	21	25	25	25	25	25
Total	283	313	312	312	312	312	312

IT Dev reductions due to Co Source
CIO increase attributed to SIO
IT Security 4 incrementals

Does not include interns.

Supplemental Contractors by Work Group

Work Group or Type of Work	June 30, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
IT Infrastructure & Ops	17	17	17	16	16	16	16
IT Dev & Support	23	23	11	11	11	11	11
IT Business Services	6	6	6	6	6	6	6
IT Security	-	-	-	-	-	-	-
Total	46	46	34	33	33	33	33

2017-2023 Headcount Totals & Changes

	Year-End						
	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Employees							
TOTAL From (Page 17)	**286**	**313**	**312**	**312**	**312**	**312**	**312**
Prior Plan		312	315	316	316	316	316
Change From Prior Plan		1	(3)	(4)	(4)	(4)	(4)

	2018 FC	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Supplemental Contractors (Page 18)	46	34	33	33	33	33
Prior Plan	31	31	31	31	31	31
Change from Prior Plan	15	3	2	2	2	2

Total Workforce (Employees Plus Supplemental Contractors)

Current Plan	359	346	345	345	345	345
Prior Plan	343	346	347	347	347	347
Change from Prior Plan	16	0	-2	-2	-2	-2

Plan Risks

- Approximately 67 employees are at risk to capital labor for the 2019BP, approximately $11.4m. Any reductions to the capital plan will adversely impact staffing levels.
- Resources are tied to the AMS schedule in order achieve benefits consistent with business case.
- Acquiring skilled IT resources will continue to be a challenge for us and the rest of the industry. IT unemployment levels constrain the available population of employees and contractor resources for hire.
- There will be a skill-set shift due to the increased level of employee retirements.

Plan Risks

- Changes in vendor pricing models from on-premise technology to subscriptions could lead to increased O&M.
- Planned levels of spend do not include unplanned business initiatives that may have an IT staffing and O&M impact.
- Vendors are driving more frequent upgrades as they invest their development budgets towards the cloud.
- While we have planned measures to protect the company from Cybersecurity threats, the nature and volume could increase the impact to the company.

Customer Services
LG&E and KU Utilities
2019 Operating Plan

September 2018 – Updated to reflect KPSC AMS ruling

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Plan Highlights

Customer focus is a core value at LG&E and KU. Customer Services strives to provide safe, reliable, and reasonable cost of service to our customers, improving the quality of life in the areas we serve. Additionally, we are committed to enhancing our relationship with our customers by delivering positive experiences that create value and build trust.

Funding levels within the proposed plan are established with the following priorities in mind:

- Employee and public safety including compliance with industry regulatory requirements
- Focus on economic development and emerging technologies
- Continuing some Energy Efficiency programs and services for our customers
- Investing in technology to enhance customer experience
- Facility construction and renovation to address operational needs
- Maintaining operational performance levels
- Managing “best in class” bad debt expense

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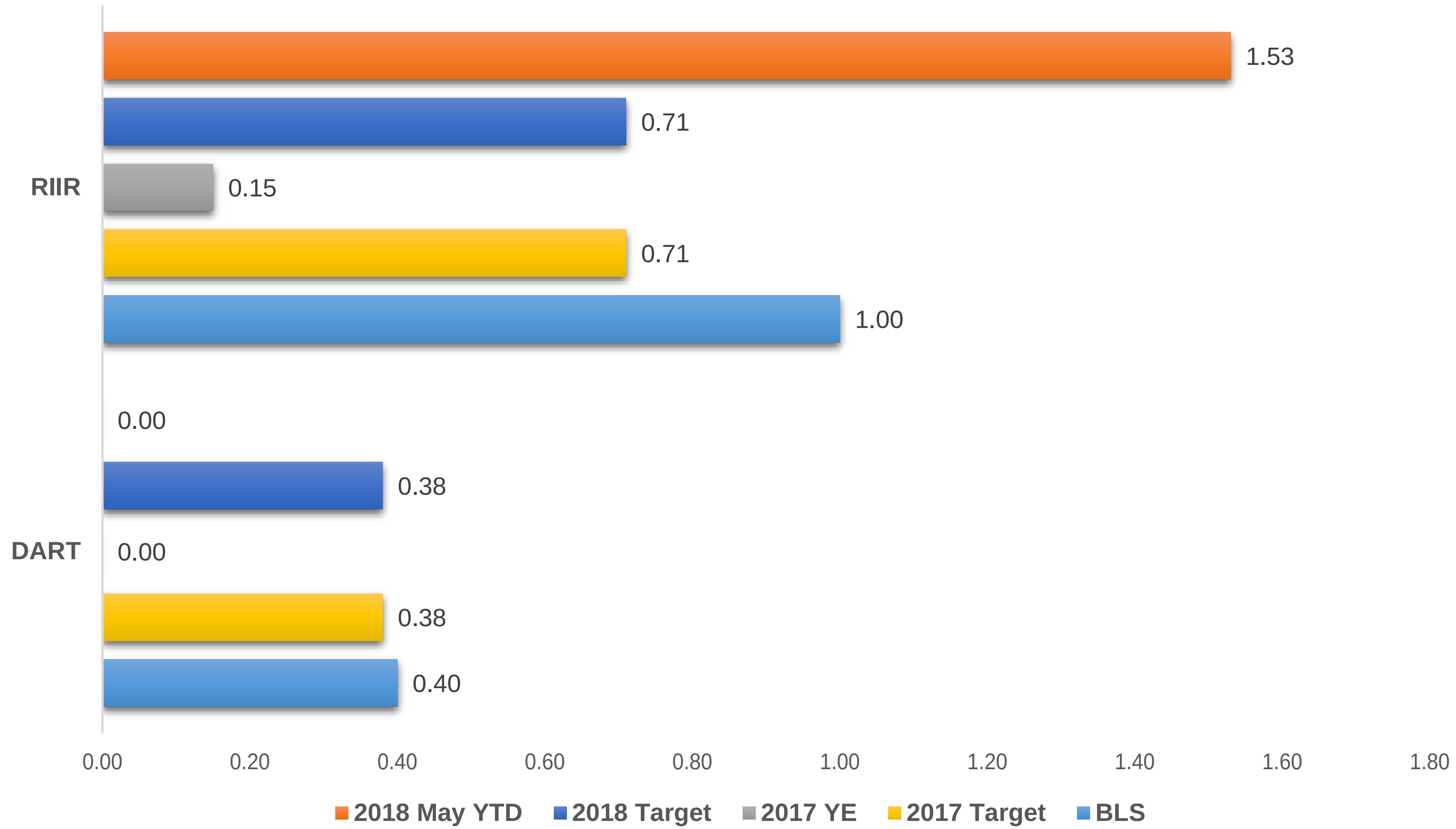
Plan Highlights

Safety Performance – Customer Service



2016 BLS - most recent data

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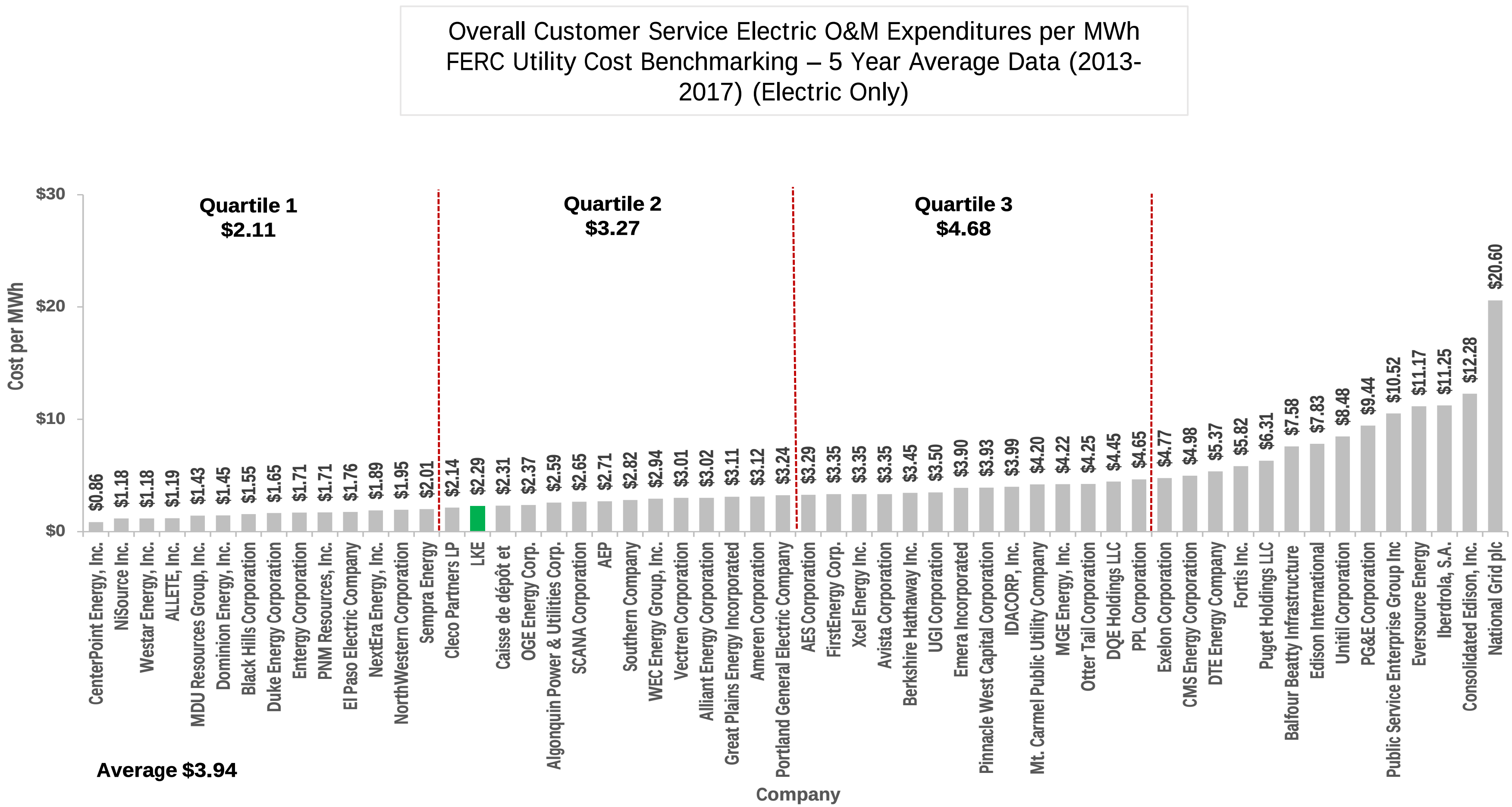
LG&E KU PPL companies

Plan Highlights

Total Customer Service Electric O&M Cost per MWh



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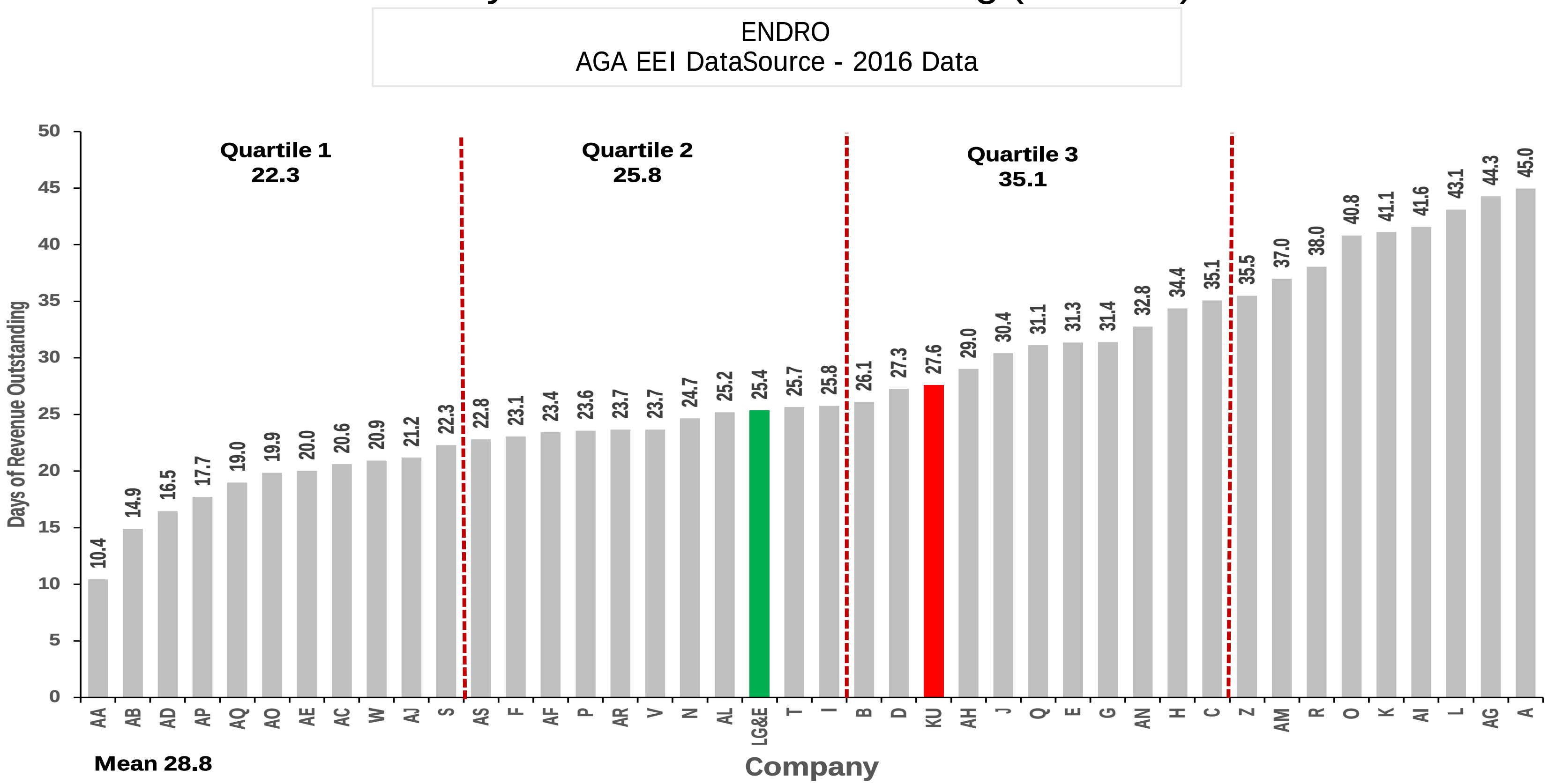
LG&E KU PPL companies

Plan Highlights

Estimated Number of Days of Revenue Outstanding (ENDRO)

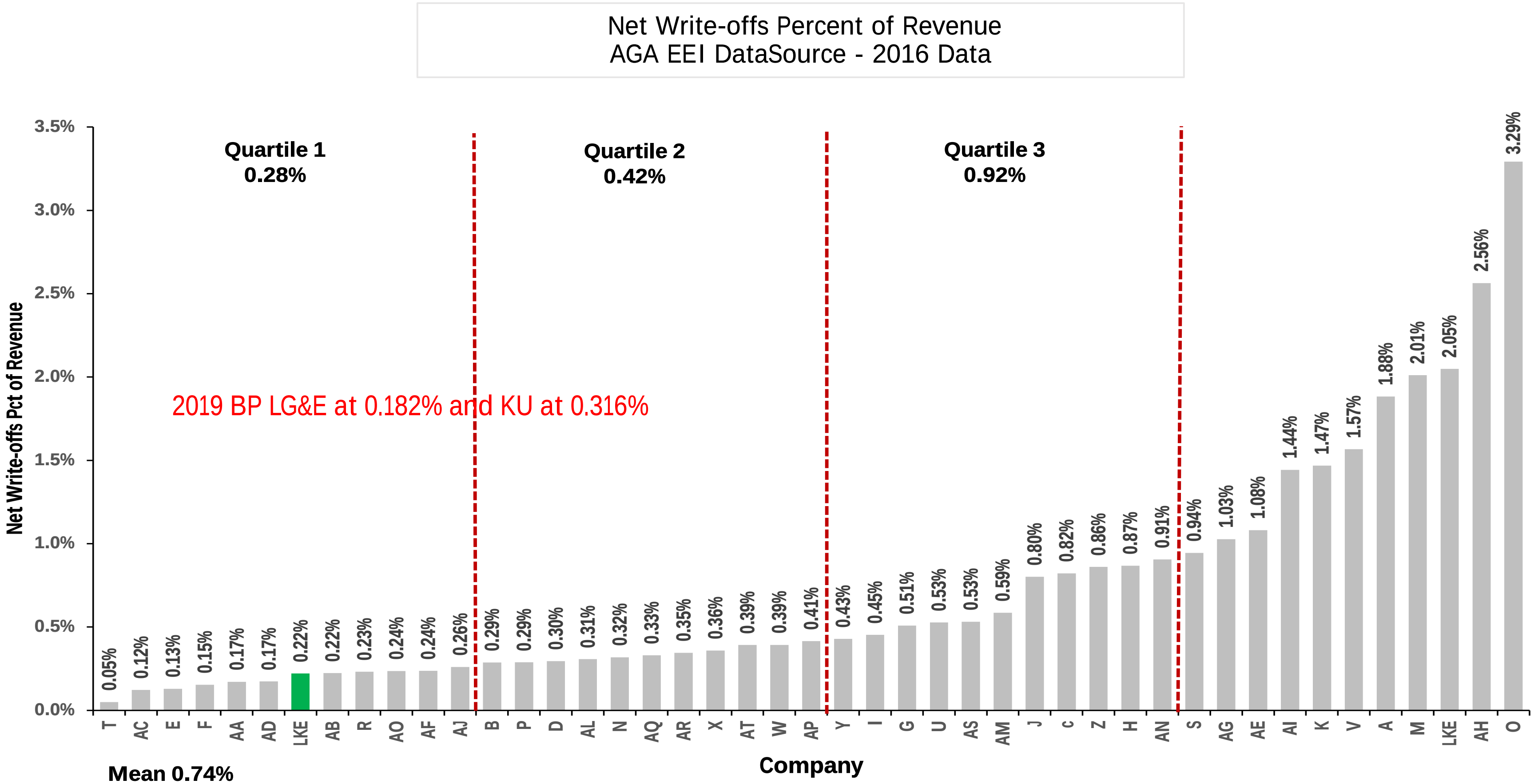


Note: January 2013 Rate Case granted customers more time to pay (minimum 22 calendar days vs. 12 calendar days).

Note: The 2018 (2017 data) AGA EEI DataSource ENDRO Peer comparison will not be available until Fourth Quarter 2018.

Plan Highlights

Net Write-Offs as a Percent of Revenues to Ultimate Customers



Note: The 2018 (2017 data) AGA EEI DataSource Net Write-Offs as a Percent of Revenues of Billed Revenues Peer comparison will not be available until Fourth Quarter 2018.

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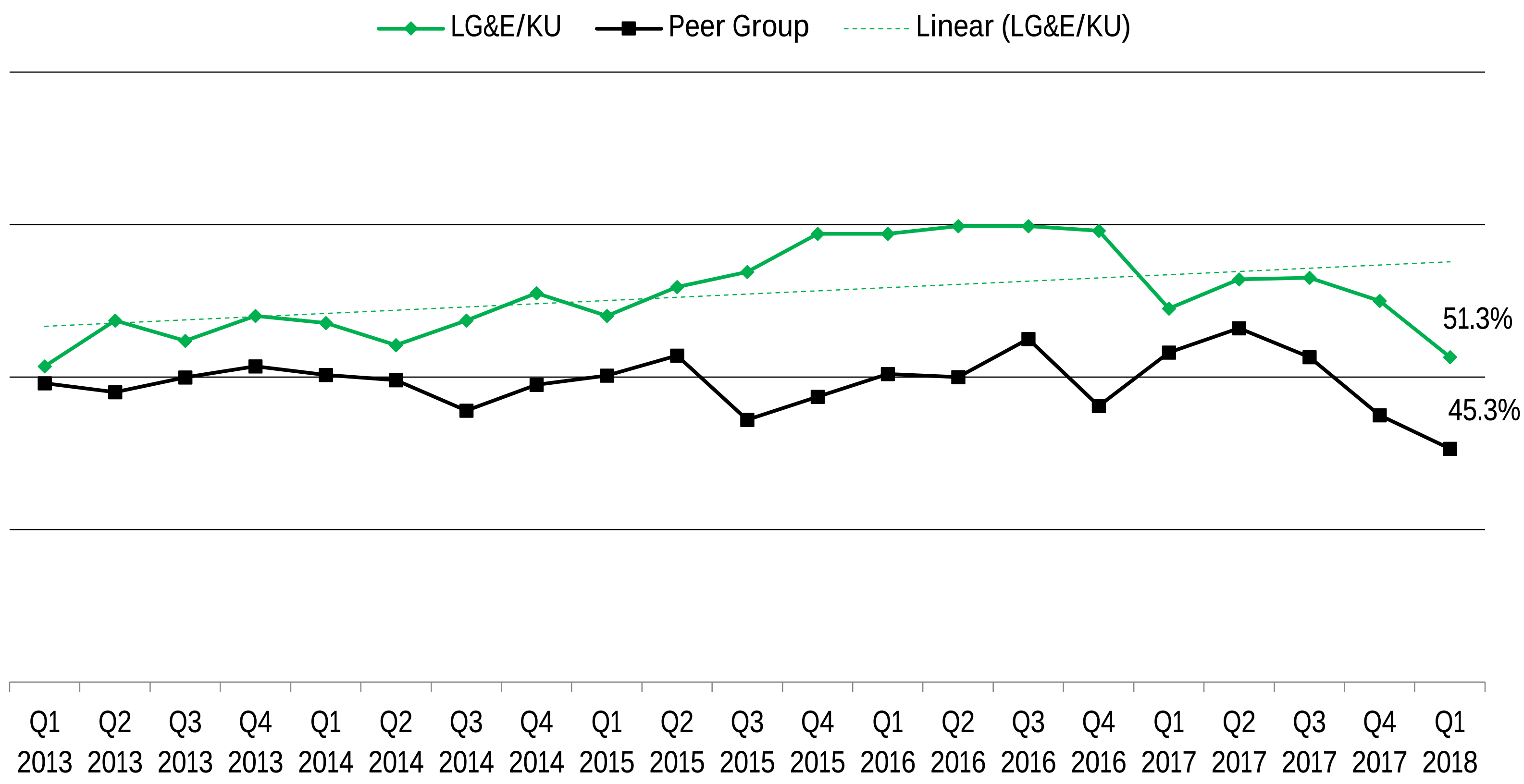
LG&E KU PPL companies

Plan Highlights

Residential Customers – Satisfaction Survey

Measured as "Top Two Box" (score of 9 or 10 on 10-point scale)



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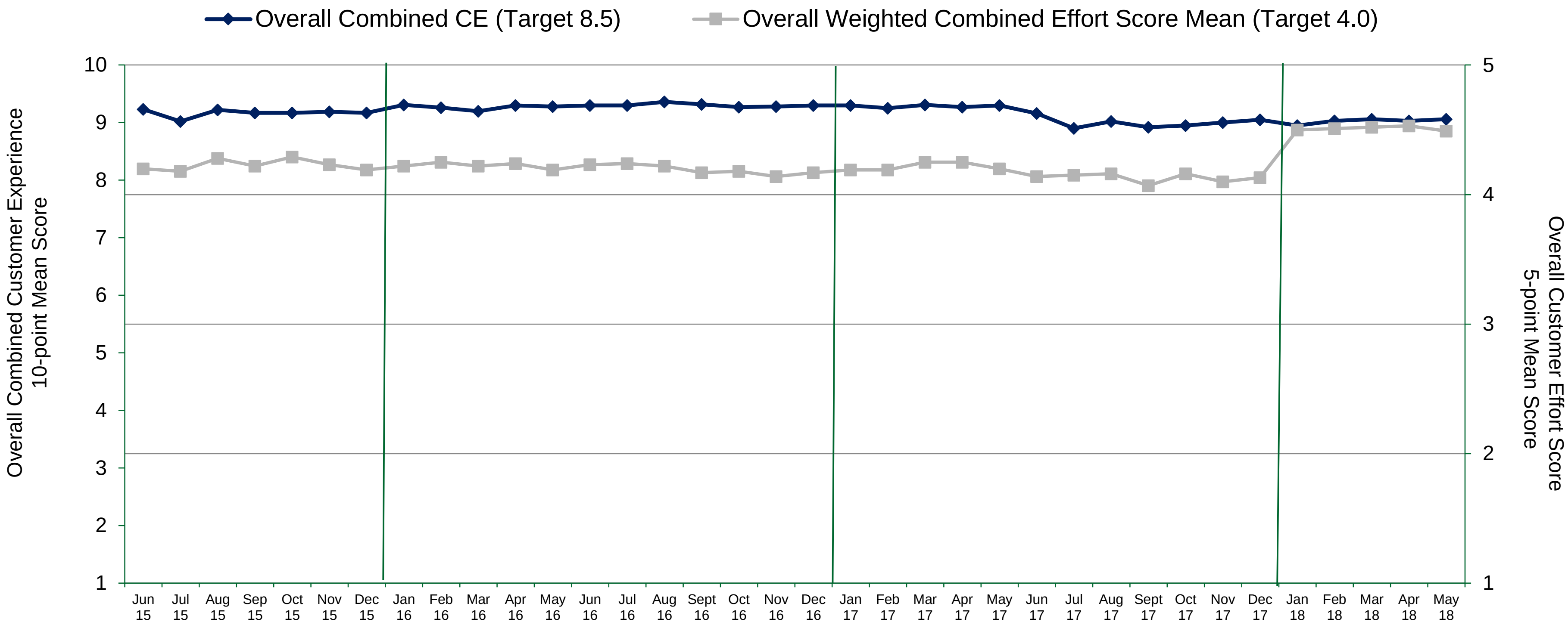
LG&E KU PPL companies

Plan Highlights

All Customer Contact Channels

Combined “Customer Experience” vs “Combined Effort” Score



Combined scores = Residential and Business agent and self serve contact channels, weighted by channel volumes.
Note: In January 2018, the wording of the question for measuring the Effort Score was simplified due to respondent confusion around the previous wording. Effort perceptions are now being asked as “Ease of Completing”.
Note: Residential and Business IVR transaction surveys were discontinued in 2016.

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LG&E KU
PPL companies

Plan Highlights

- Safety and Wellness
  - Maintain industry leading performance
  - Implement formalized safety structure within Customer Services to focus on both field and office hazards, understanding of safety processes and timely delivery of consistent messaging
  - Enhance operational effectiveness within the COO organization
  - Support the transfer of safety knowledge from seasoned to new employees
  - Ensure a comprehensive safety/technical training plan is in place for all employees
  - Continue to improve workforce, business partners and public safety
  - Continue to improve motor vehicle safety
  - Identify, share and capitalize on industry best practices
  - Promote wellness initiatives as an aspect of safety

Plan Highlights

- Customer Experience
  - — Advance corporate-wide "Customer Experience" strategy/initiative
  - — Continue investments in technology to enhance digital customer experience
    - Offer limited "Chat" assistance to Corporate Website visitors in 2018, expand offerings in 2019-2023
    - Expand and improve "My Account" offerings annually and upgrade Outage Map
    - Advance "My Notifications" in response to customer requests for reminders and information
    - Pilot At-Home Agents to improve response time to customer inquiries and employee satisfaction
  - — Enhance our "Customer Advocacy" role through partnerships with customer focus groups
  - — Continue commitment to corporate citizenship and community involvement

Plan Highlights

- Customer Experience
  - — Continue to assist low-income customers through energy efficiency programs and partnerships with advocacy groups
    - By year-end 2018, improve low-income website to include both pledge and payment of assistance funds
  - — Advance our understanding of customer behavior while gaining insight into customer needs
  - — Pursue tariff changes to drive positive impact on customer experience such as Green tariff, EDR enhancements and one-time LPC waiver
  - — Continue to educate customers on renewable offerings and encourage participation by implementing program enhancements

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Major Assumptions

- The "Customer Experience" will continue to be a significant focus across the Company.
- Customer expectations regarding levels of service, digital experience and availability of information will continue to increase.
- The Company will increase focus on emerging businesses that provide customer solutions and drive economic development.
- Bad debt expense is based on .182% of projected revenues for LG&E and .316% of projected revenues for KU through the planning period.
- Contact center pay rate increases are based off market survey data and support maintaining a competitive position within the local market.
- New contracts for Meter Reading and Field Services will require increased funding in light of the strong economy.

Major Assumptions

- DSM cost of sales reflected in the Plan assume a level of cost effective programming beginning 1/1/2019. The DSM case creates unknowns around labor and outside services within the BP timeframe.
- The Solar Share Facility project for the first array will begin in 2018, with one additional 500kW facility built each year of the plan.

2017-2023 Annual O&M Expenses
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Expenses Only:							
Labor	41,095	42,629	45,730	47,127	48,184	49,429	50,779
Supplemental Contractors	20,479	21,661	25,003	28,404	29,821	30,990	31,388
Other Outside Services	9,464	9,619	10,334	10,418	10,623	10,862	11,233
Materials & Supplies	2,231	2,371	2,445	2,535	2,541	2,594	2,654
Transportation	1,536	1,681	1,783	1,823	1,853	1,909	1,935
Bad Debt Expense	6,696	7,665	7,476	7,683	7,708	7,749	7,808
Postage	4,802	5,010	5,066	5,218	5,375	5,536	5,536
All Other Non-labor	6,894	7,678	7,759	7,619	7,749	7,838	7,837
Total O&M Expense - Mgmt. View	**93,198**	**98,314**	**105,597**	**110,829**	**113,853**	**116,907**	**119,171**
Plus:							
Base Gross Margin Items							
Mechanism Gross Margin Items	38,043	30,813	15,760	14,511	13,922	13,975	13,511
Total O&M Expense-GAAP View	**131,241**	**129,127**	**121,357**	**125,340**	**127,775**	**130,883**	**132,682**

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2017-2023 Annual O&M Expenses Non Labor Category ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Supplemental Contractors							
Meter Reading	7,716	8,112	11,519	14,162	14,162	14,162	14,446
Field Services	3,366	3,812	5,338	6,767	6,903	7,042	7,181
O&M for Shared Facilities	2,327	2,453	2,430	2,459	2,486	2,512	2,542
Contract Services	2,303	2,253	2,163	2,169	2,234	2,240	2,240
Corp Security & Business Continuity	1,954	2,069	2,061	2,112	2,135	2,169	2,202
Facilities Maintenance	1,263	1,392	1,394	1,359	1,394	1,455	1,339
Meter Shop	1,048	1,025	923	777	760	781	801
Business Offices	480	486	503	505	507	509	515
Gap	-	(15)	(1,530)	(2,107)	(963)	(90)	(90)
All Other	22	75	202	202	202	209	211
Total Supplemental Contractors	**20,479**	**21,661**	**25,003**	**28,404**	**29,821**	**30,990**	**31,388**
Other Outside Services							
Facilities Maintenance	2,815	2,747	2,876	2,885	2,948	3,013	3,282
Marketing & Performance	1,778	1,734	1,664	1,668	1,686	1,723	1,731
O&M for Shared Facilities	1,417	1,526	1,601	1,603	1,603	1,630	1,630
Contract Services	1,135	956	1,156	1,190	1,232	1,271	1,291
Remittance & Collection	785	828	840	843	870	900	910
Corp Security & Business Continuity	341	354	491	476	494	512	527
Energy Efficiency	60	80	422	439	456	473	497
Business Offices	422	400	276	305	305	293	302
All Other	711	994	1,009	1,011	1,029	1,047	1,064
Total Other Outside Services	**9,464**	**9,619**	**10,334**	**10,418**	**10,623**	**10,862**	**11,233**

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2017-2023 Annual O&M Expenses
Non Labor Category
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Materials & Supplies							
Business Offices	540	415	439	494	464	493	507
Marketing & Performance	362	418	418	430	441	453	462
Field Services	274	376	310	318	327	335	343
Meter Shop	151	221	292	298	303	304	313
Facilities Maintenance	100	164	187	187	187	187	179
Meter Reading	132	139	161	161	161	161	161
Residential Service Center	152	127	140	143	143	143	143
Contract Services	107	147	120	120	130	130	149
All Other	412	365	378	384	385	388	398
Total Materials & Supplies	**2,231**	**2,371**	**2,445**	**2,535**	**2,541**	**2,594**	**2,654**
Transportation							
Field Services	912	1,018	1,139	1,161	1,190	1,237	1,252
Meter Shop	221	219	248	261	256	260	267
Meter Reading	141	174	147	150	152	155	158
Facilities Maintenance	106	119	105	105	105	105	105
All Other	156	150	145	147	150	151	154
Total Transportation	**1,536**	**1,681**	**1,783**	**1,823**	**1,853**	**1,909**	**1,935**

2017-2023 Annual O&M Expenses
Non Labor Category
($000)

Item	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Bad Debt Expense					
Retail Revenue from Ultimate Consumer					
KU	1,618,110	1,660,608	1,669,306	1,677,897	1,688,722
LG&E - Electric	1,109,914	1,137,814	1,134,269	1,139,359	1,147,791
LG&E - Gas (excluding GSC)	188,067	200,280	202,419	205,243	210,184

Year & % of Revenue	Combined	LG&E	KU
2013	0.20%	0.14%	0.25%
2014	0.34%	0.26%	0.42%
2015	0.28%	0.19%	0.35%
2016	0.22%	0.15%	0.28%
2017	0.23%	0.16%	0.28%
Simple Average	0.25%	0.18%	0.32%

Net Charge Offs ($000s)					
KU Retail Revenue	5,113	5,248	5,275	5,302	5,336
LG&E Retail - Electric	2,020	2,071	2,064	2,074	2,089
LG&E Retail - Gas (excluding GSC)	342	365	368	374	383
Total Bad Debt Expense	7,476	7,683	7,708	7,749	7,808

2017-2023 Annual O&M Expenses
Non Labor Category
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Other Nonlabor							
Rent	3,741	3,764	4,048	3,992	3,940	3,914	3,861
Meals	764	897	894	899	902	914	919
Phone & Telecomm	438	495	531	533	541	549	548
Mileage	422	285	353	337	340	347	350
Travel	268	378	239	253	252	254	265
Training	170	261	220	217	234	232	243
Utilities	269	228	155	155	155	155	155
Rights of Way	301	326	303	294	302	319	326
O&M for Shared Facilities	328	371	329	329	329	329	329
All Other	195	673	687	609	753	826	841
Total Other Nonlabor	**6,894**	**7,678**	**7,759**	**7,619**	**7,749**	**7,838**	**7,837**

2017-2023 Annual Expenses Mechanism Gross Margin Items ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
DSM Costs							
Residential Audit	2,690	2,409	-	-	-	-	-
Residential WeCare	6,529	6,526	6,335	6,341	6,347	6,667	6,359
Residential Demand	8,274	5,684	3,586	2,378	2,600	2,365	2,359
Residential Incentives	4,319	2,229	-	-	-	-	-
Residential Refrigeration Removal	1,888	1,411	-	-	-	-	-
Smart Energy Profile	2,266	562	-	-	-	-	-
Advanced Metering Systems	255	329	394	428	411	445	433
Commercial Rebate	4,306	3,954	2,835	2,856	2,774	2,543	2,543
Commercial Demand	1,064	1,067	939	843	847	1,003	854
KSBA	233	759	725	725	-	-	-
Education & Information	4,084	3,008	-	-	-	-	-
Development & Administration	1,954	2,648	724	733	742	751	760
Total DSM	37,861	30,585	15,539	14,303	13,720	13,774	13,308
Bad Debt Expense (GSC)	181	228	221	208	202	202	203
Total Mechanism Gross Margin	38,043	30,813	15,760	14,511	13,922	13,975	13,511

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2017-2023 Annual Expenses Mechanism Gross Margin Items ($000)

Item	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Bad Debt Expense					
Retail Revenue from Ultimate Consumer					
LG&E - GSC	130,037	122,171	119,004	118,572	119,513

Year & % of Revenue	LG&E
2013	0.10%
2014	0.24%
2015	0.21%
2016	0.14%
2017	0.15%
Simple Average	0.17%

	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Net Charge Offs ($000s)					
LG&E Retail - Gas (excluding GSC)	221	208	202	202	203

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O&M Annual Expense Reconciliation ($000)

	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
2018 Plan/Expectation	99,423	97,526	95,157	95,531	97,769
Drivers:					
Bad Debt Expense	(559)	(569)	(867)	(1,082)	(1,463)
Field Services & Meter Reading Contractors	4,333	8,275	8,408	8,543	8,729
AMS Savings not in 2019 BP	-	2,706	8,192	10,935	11,154
Meter Shop Impacts w/o AMS	(551)	(473)	(592)	(680)	(714)
Call Centers & Business Office Rate Change	2,580	2,567	2,683	2,784	2,861
Workforce Plan Impacts	150	154	224	233	243
Customer Education	215	229	229	224	245
CRM System (Sales Force)	125	125	125	125	125
Estimated Sales Tax on Services	120	120	120	120	120
All Other	(238)	170	174	174	101
Current Plan - Mgt. View	105,597	110,829	113,853	116,907	119,171

2017-2023 Capital Expenditures
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Demand Load Control	1,614	(50)	-	-	-	-	-
AMS Opt-In	117	450	500	61	63	65	67
Total DSM Projects	**1,732**	**399**	**500**	**61**	**63**	**65**	**67**
Community Solar	-	1,832	919	914	914	2,211	914
Business Solar	-	90	-	-	-	-	-
Meter Purchases	7,617	5,920	6,488	5,213	5,320	5,489	5,588
MV-90 Daily Read	-	727	767	-	-	-	-
Facility Consolidation	10	2,240	2,853	5,029	6,511	-	-
Facility Relocation Property	-	20	643	-	-	513	-
Facility & Site Improvements	8,201	9,717	11,105	7,413	12,113	3,832	3,493
South Ops Engineering Center	-	-	2,701	4,212	3,573	-	-
Riverport Roof	-	-	-	-	4,600	-	-
KUGO Remodel	-	-	500	4,498	3,498	-	-
Distribution Control Center	1,671	6,913	4,305	-	-	-	-
BOC Heating Project	-	99	2,000	1,500	-	-	-
Furniture & Equipment	1,272	1,145	1,260	1,178	1,340	964	985
Tenant Improvements	1,811	1,386	1,255	-	-	-	-
Fire & Security Systems	587	528	449	449	449	449	449
All Other	1,059	595	900	1,183	1,213	1,227	1,237
Total Capital	**23,958**	**31,612**	**36,644**	**31,650**	**39,594**	**14,750**	**12,733**
2018 Plan		**32,207**	**31,844**	**28,028**	**34,625**	**15,995**	**18,070**
Change		**(595)**	**4,800**	**3,623**	**4,969**	**(1,245)**	**(5,337)**

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Labor Expense

	2019									
Salary Plan	Average Headcount	Base Salary	Overtime and all Other Labor*	TIA Labor Expense	Total Salary & TIA Labor	2019 Labor Expense	2020 Labor Expense	2021 Labor Expense	2022 Labor Expense	2023 Labor Expense
Exempt	166	$ 16,192	$ -	$ 1,602	$ 17,794					
Non-Exempt	429	$ 19,465	$ 1,310	$ 1,980	$ 22,755					
Union / Non-Union Hourly	102	$ 7,017	$ 639	$ 554	$ 8,210					
Subtotal	697	$ 42,674	$ 1,948	$ 4,136	$ 48,759					
Co-ops / Interns	4	$ 87	$ -	$ -	$ 87					
Total	701	$ 42,761	$ 1,948	$ 4,136	$ 48,846	$45,730	$47,127	$48,184	$49,429	$50,779

Note: Annual expense amounts are on an income statement basis and exclude balance sheet accounts.

Employee Headcount by Work Group

Work Group or Major Dept.	Jun 30, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
VP	2	2	2	2	2	2	2
Operating Services & Corporate Security	59	61	60	60	60	60	60
Revenue Integrity	211	220	225	227	227	227	227
Customer Services & Marketing	376	395	395	395	395	395	395
Energy Efficiency	14	14	14	15	15	15	15
Interns	5	5	4	4	4	4	4
Total	667	697	700	703	703	703	703

Supplemental Contractors by Work Group

Work Group or Major Dept.	Jun 30, 2018 Actual	Dec 31, 2018	Dec 31, 2019	Dec 31, 2020	Dec 31, 2021	Dec 31, 2022	Dec 31, 2023
Energy Efficiency	106	106	88	88	88	88	88
Revenue Integrity	264	264	275	256	256	256	256
Operating Services & Corporate Security	214	214	211	211	211	211	211
Customer Service & Marketing	20	23	23	23	23	23	23
Total	604	607	597	578	578	578	578

2017-2023 Headcount Totals & Changes

	Year-End						
	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Employees							
TOTAL From Page 25	**686**	**697**	**700**	**703**	**703**	**703**	**703**
Prior Plan		705	705	705	705	705	
Change From Prior Plan		(8)	(5)	(2)	(2)	(2)	

	2018 FC	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Supplemental Contractors (Page 26)	607	597	578	578	578	578
Prior Plan	596	540	492	389	338	
Change from Prior Plan	11	57	86	189	240	

Total Workforce (Employees Plus Supplemental Contractors)

Current Plan	1,304	1,297	1,281	1,281	1,281	1,281
Prior Plan	1,301	1,245	1,197	1,094	1,043	
Change from Prior Plan	3	52	84	187	238	

Plan Risks

- Increased capital and O&M costs due to industry regulatory actions
- Customer hardship and uncollectible accounts
- Customer satisfaction impacts due to ongoing rate case filings
- IT and business resource and financial constraints on ability to implement technology to meet customer expectations in enhancing the customer experience
- Customer satisfaction, regulatory issues and DSM headcount, depending upon the level of post-2018 DSM program offerings
- The timing of each solar facility is subject to customer education and resulting participation levels.

Operational Performance

Key Performance Indicators

KPI	2017 Year End	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Safety - Employees [1]	0.15	1.30	0.71	0.71	0.71	0.71	0.71
Safety - Contractors [1]	3.25	4.40	1.80	1.73	1.66	1.55	1.47
DART - Employees [1]	0.00	0.00	0.38	0.38	0.38	0.38	0.38
Overall Customer Experience	9.11	8.50	8.50	8.50	8.50	8.50	8.50
Overall Customer Satisfaction (TIA Points)	26.00	18.00	18.00	18.00	18.00	18.00	18.00
LKE Service Order Days to Complete [2]	0.30	1.00	1.00	1.00	1.00	1.00	1.00
O&M Cost per MWH Sold - 5-Year Average Calculation	2.29	2.37	2.39	2.41	2.40	2.38	2.38

[1] 2018 Forecast numbers are YTD June 2018 actuals and not forecasted.

[2] Measures the time between the scheduled date and the completed service order date (excludes credit and adjustment-related service orders).

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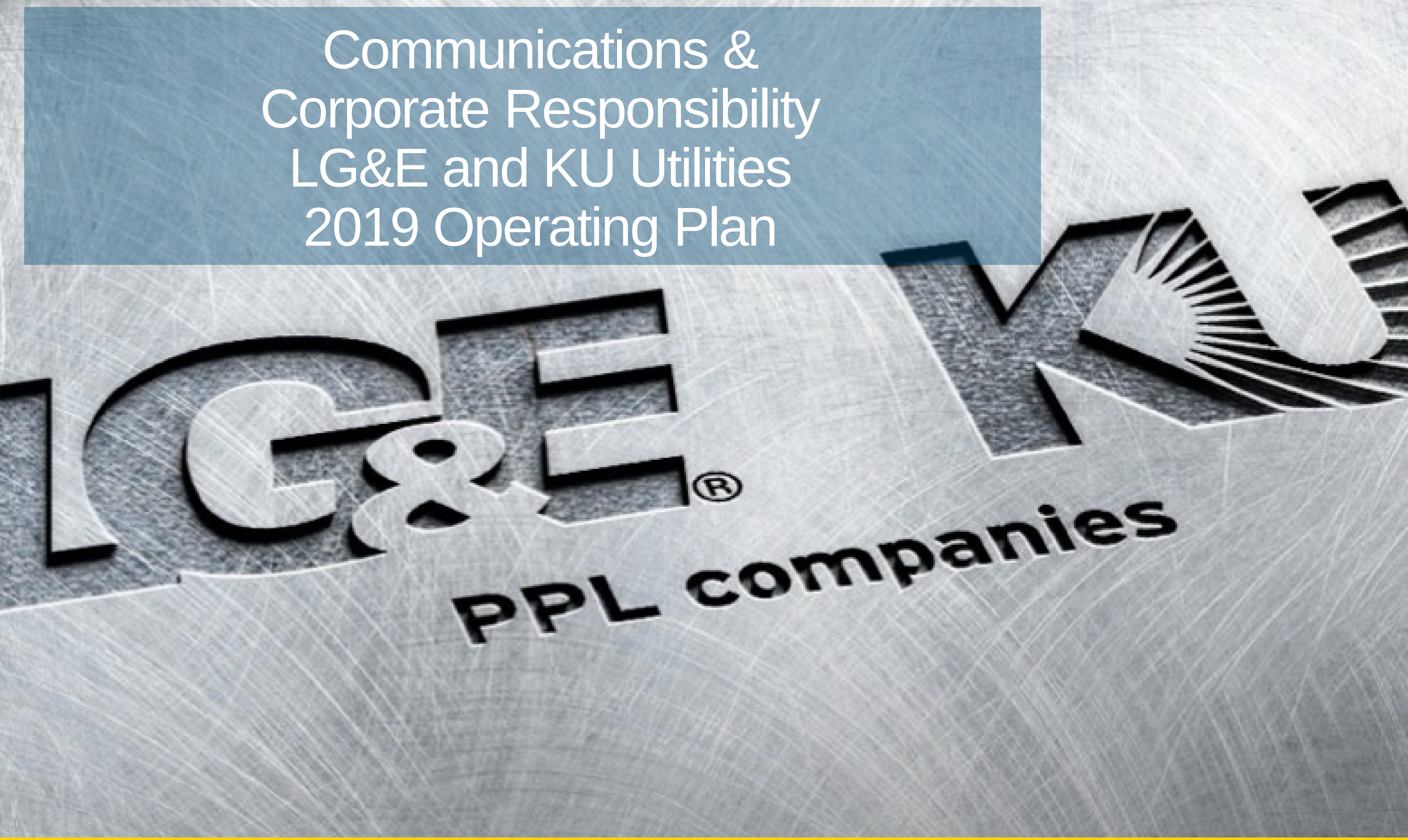
LG&E KU PPL companies

Communications & Corporate Responsibility LG&E and KU Utilities 2019 Operating Plan



August 2018

LG&E KU
PPL companies

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- Financial Performance
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  - o Labor Expense
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- Plan Risks

Plan Highlights

- The five-year plan for Communications and Corporate Responsibility is designed to sufficiently educate customers on energy choices and ways to save energy and money through tips, tools and initiatives.

Major Assumptions

- Corporate Communications
  - Educating customers on their energy choices and ways to reduce their usage through energy efficiency tips, tools and initiatives will require us to continue to utilize surround sound approach for communications tactics.
  - LG&E and KU communications preferences will require segmented communications and advertising strategies.

Major Assumptions

- Corporate Responsibility and Community Affairs
  - Criticism and scrutiny, if any, in aftermath of rate case filing does not necessitate extraordinary community investment response.
  - Criticism and scrutiny of the DSM programs going away does not necessitate extraordinary community investment.
  - Criticism and scrutiny from environmental groups does not escalate dramatically.
  - No significant deterioration in customer satisfaction ratings from low-income customers.
  - Our corporate-wide sustainability program responsibilities do not increase.

2017-2023 Annual O&M Expenses ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Expenses Only:							
Labor	$ 2,597	$ 2,743	$ 2,800	$ 2,891	$ 2,965	$ 3,031	$ 3,121
Supplemental Contractors	$ 111	$ 248	$ 263	$ 263	$ 263	$ 263	$ 263
Advertising							
Customer Education	$ 494	$ 476	$ 2,937	$ 2,937	$ 2,937	$ 2,937	$ 2,936
Brand	$ 1,958	$ 2,263	$ 2,253	$ 2,275	$ 2,293	$ 2,311	$ 2,330
Outside Services	$ 576	$ 667	$ 1,516	$ 1,516	$ 1,516	$ 1,516	$ 1,516
All Other Non-Labor	$ 277	$ 472	$ 445	$ 445	$ 444	$ 445	$ 445
Total O&M Expense - Mgmt. View	**$ 6,013**	**$ 6,869**	**$ 10,214**	**$ 10,327**	**$ 10,418**	**$ 10,503**	**$ 10,611**

2017-2023 Annual O&M Expenses
Advertising
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Customer Newsletter, Mailings	$ 459	$ 398	$ 579	$ 579	$ 579	$ 579	$ 579
Customer Education Advertising	$ 35	$ 79	$ 2,358	$ 2,358	$ 2,358	$ 2,358	$ 2,358
Image Advertising	$ 889	$ 870	$ 870	$ 870	$ 870	$ 870	$ 870
Sports Advertising	$ 606	$ 653	$ 724	$ 741	$ 759	$ 777	$ 795
Sponsorship	$ 191	$ 305	$ 255	$ 260	$ 260	$ 260	$ 260
Native Content	$ 179	$ 160	$ 160	$ 160	$ 160	$ 160	$ 160
Print Ads and Native Content	$ 77	$ 95	$ 95	$ 95	$ 95	$ 95	$ 95
Miscellaneous	$ 16	$ 179	$ 150	$ 150	$ 150	$ 150	$ 150
Total Advertising	$ 2,452	$ 2,739	$ 5,190	$ 5,212	$ 5,230	$ 5,248	$ 5,266

LG&E KU
PPL companies

2017-2023 Annual O&M Expenses
Outside Services
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Agency of record	$ 131	$ 168	$ 911	$ 911	$ 911	$ 911	$ 911
Photography, Video	$ 50	$ 134	$ 183	$ 183	$ 183	$ 183	$ 183
Media Monitoring	$ 137	$ 139	$ 149	$ 149	$ 149	$ 149	$ 149
The Cubero Group	$ 51	$ 84	$ 134	$ 134	$ 134	$ 134	$ 134
Other-Communications	$ 187	$ 65	$ 65	$ 65	$ 65	$ 65	$ 65
Other-Corporate Resp.	$ 20	$ 77	$ 74	$ 74	$ 74	$ 74	$ 74
Total Outside Services	$ 576	$ 667	$ 1,516	$ 1,516	$ 1,516	$ 1,516	$ 1,516

O&M Annual Expense Reconciliation ($000)

	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
2018 Plan/Expectation	$ 7,226	$ 7,255	$ 7,443	$ 7,535	$ 7,671
Drivers:					
Customer Education Advertising	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 2,250
Outside Services	$ 769	$ 769	$ 769	$ 769	$ 761
All Other	$ (31)	$ 53	$ (44)	$ (51)	$ (71)
Current Plan - Mgt. View	$ 10,214	$ 10,327	$ 10,418	$ 10,503	$ 10,611

Labor Expense

Salary Plan	2019 Average Headcount	2019 Base Salary	2019 Overtime and all Other Labor*	2019 TIA Labor Expense	2019 Total Salary & TIA Labor	2019 Labor Expense	2020 Labor Expense	2021 Labor Expense	2022 Labor Expense	2023 Labor Expense
Exempt	23	$ 2,365	$ -	$ 241	$ 2,606					
Non-Exempt	3	$ 168	$ -	$ 17	$ 185					
Union / Non-Union Hourly	-	$ -	$ -	$ -	$ -					
Subtotal	26	$ 2,533	$ -	$ 258	$ 2,791					
Co-ops / Interns	1	$ 14	$ -	$ 2	$ -					
Total	27	$ 2,547	$ -	$ 260	$ 2,791	$ 2,800	$ 2,891	$ 2,965	$ 3,031	$ 3,121

Note: Annual expense amounts are on an income statement basis and exclude balance sheet accounts.

Employee Headcount by Work Group

Department	May 31, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
Communications	19	20	20	20	20	20	20
Corporate Responsibility	5	6	6	6	6	6	6
Total	24	26	26	26	26	26	26

Supplemental Contractors by Work Group

Department	May 31, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
Communications	1	1	1	1	1	1	1

2017-2023 Headcount Totals & Changes

	Year-End						
	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Employees							
TOTAL From Page 11	**25**	**26**	**26**	**26**	**26**	**26**	**26**
Prior Plan		26	26	26	26	26	
Change From Prior Plan		0	0	0	0	0	

	2018 FC	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Supplemental Contractors Page 12	1	1	1	1	1	1
Prior Plan	1	1	1	1	1	1
Change from Prior Plan	0	0	0	0	0	0

Total Workforce (Employees Plus Supplemental Contractors)

Current Plan	27	27	27	27	27	27
Prior Plan	27	27	27	27	27	27
Change from Prior Plan	0	0	0	0	0	0

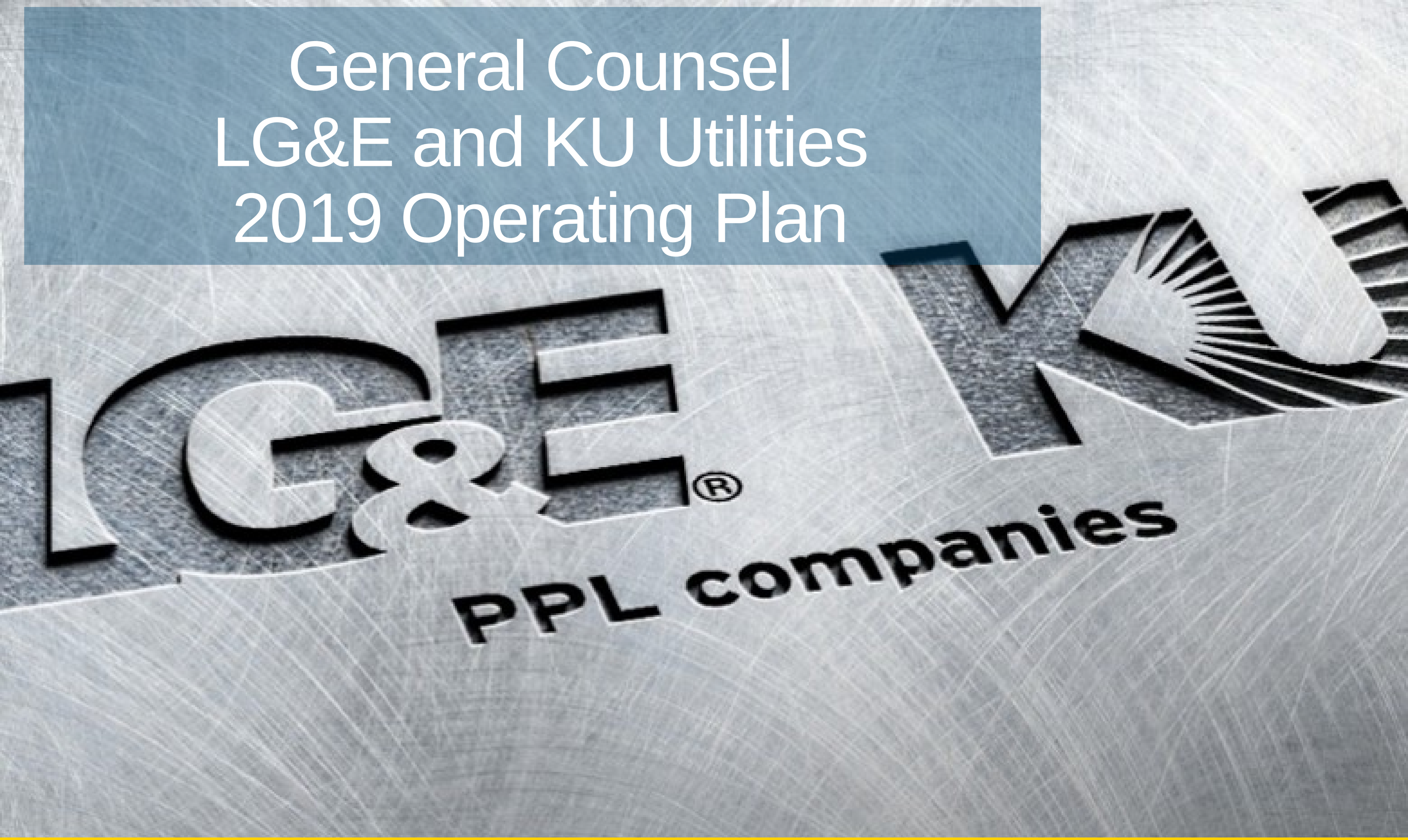
Plan Risks

- Corporate Communications
  - Reduction in energy efficiency programs could still impact customer satisfaction levels.
  - Continued increases in customer bills could potentially result in lower customer satisfaction levels.
  - Ruling on AMS alters the amount of funding for education of the new meters.
  - Opposition to net metering, smart meters and the CCR rule could result in litigation and adverse media exposure.

Plan Risks

- Corporate Responsibility and Community Affairs
  - Adverse weather and/or natural disasters may necessitate new levels of assistance for agencies addressing the needs of our challenged customers.
  - Reduction in energy efficiency programs could result in different community relations activities.
  - Dissatisfaction with AMS may require additional community relations actions.
  - Unfavorable legal or regulatory result may require focused community relations strategy.

General Counsel
LG&E and KU Utilities
2019 Operating Plan



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Plan Highlights

- General Counsel provides support to the entire company through Legal, Compliance, Federal Regulation & Policy, and External Affairs.
- The 2019 General Counsel budget is under expectation by $140k.
- Outside Counsel is 46% of the overall General Counsel budget.
- Headcount will remain flat throughout the plan.
  - Labor represents 27% of the General Counsel 2019BP O&M expenses.
- Company Dues represents 8% of the General Counsel 2019BP O&M expenses.

Major Assumptions

- Legal
  - — Hourly rates of outside providers remain stable.
  - — Pending and anticipated legal matters proceed within a band of predictability.
  - — There are no material, unanticipated legal issues which arise.

Major Assumptions

- Compliance
  - — No significant changes in the role played by Compliance Department.
    - A driver for change could be modified expectations, new interpretations of current regulations, significant new or revised regulatory requirements, or increased demand for support from the business teams to reduce regulatory risks.
  - — Limited PHMSA involvement beyond administration of new program
    - Recent implementation of new PHMSA compliance program involved reallocation of existing resources, but developments in that program could create additional resource needs.

Major Assumptions

- Federal Regulation & Policy
  - Generally routine pace of rulemaking or policy initiatives from FERC continues.
  - Continued moderate engagement by the Company in EEI or other industry group activities.
  - No targeted initiatives by Company to influence a particular policy matter.
  - No other major developments at FERC or other forums (e.g., PHMSA) that will dictate fundamentally different resource needs.

Major Assumptions

- External Affairs
  - Expectation that at least one 2019 legislative issue will require modest outside communications agency spending.
  - Convergence of legislative, regulatory and legal issues expected to continue (e.g. Solar Share and Planning and Zoning legislation, change in Basic Service Charge and legislation limiting the same, potential change in net metering statute requiring filing of new tariffs, etc.).

2017-2023 Annual O&M Expenses ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Expenses Only:							
Labor	$ 4,345	$ 4,926	$ 4,869	$ 5,035	$ 5,184	$ 5,296	$ 5,430
Outside Counsel	$ 4,914	$ 7,333	$ 8,213	$ 8,295	$ 8,378	$ 8,462	$ 8,546
Outside Services	$ 1,099	$ 1,559	$ 1,096	$ 1,186	$ 1,086	$ 1,096	$ 1,186
EEI Dues	$ 729	$ 685	$ 747	$ 766	$ 785	$ 804	$ 825
Environmental Company Dues	$ 687	$ 713	$ 708	$ 708	$ 708	$ 708	$ 708
All Other Non-Labor	$ 2,257	$ 2,353	$ 2,245	$ 2,252	$ 2,248	$ 2,245	$ 2,287
Total O&M Expense - Mgmt. View	**$ 14,031**	**$ 17,569**	**$ 17,879**	**$ 18,242**	**$ 18,389**	**$ 18,612**	**$ 18,982**

2017-2023 Annual O&M Expenses
Outside Counsel
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Regulatory	$ 1,715	$ 1,936	$ 3,673	$ 3,710	$ 3,747	$ 3,784	$ 3,822
Litigation	$ 1,710	$ 3,073	$ 2,086	$ 2,107	$ 2,128	$ 2,149	$ 2,170
Environmental	$ 498	$ 446	$ 1,645	$ 1,661	$ 1,678	$ 1,695	$ 1,712
All Other	$ 991	$ 1,878	$ 810	$ 818	$ 826	$ 834	$ 842
Total Outside Counsel	$ 4,914	$ 7,333	$ 8,213	$ 8,295	$ 8,378	$ 8,462	$ 8,546

2017-2023 Annual O&M Expenses
Outside Services
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Legal Consulting	$ 624	$ 1,173	$ 672	$ 672	$ 672	$ 672	$ 672
Legal e-Discovery Vendor	$ 205	$ 248	$ 248	$ 248	$ 248	$ 248	$ 248
Legal Other	$ 164	$ 138	$ 148	$ 148	$ 148	$ 148	$ 148
Compliance - Mock Audit	$ 104	$ -	$ -	$ 100	$ -	$ -	$ 100
All Other	$ 2	$ -	$ 28	$ 18	$ 18	$ 28	$ 18
Total Outside Services	$ 1,099	$ 1,559	$ 1,096	$ 1,186	$ 1,086	$ 1,096	$ 1,186

O&M Annual Expense Reconciliation ($000)

	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
2018 Plan/Expectation	$17,966	$18,199	$18,477	$18,806	$19,037
Drivers:					
Labor	$ (251)	$ (289)	$ (272)	$ (277)	$ (309)
Outside Counsel	$ 70	$ 71	$ 72	$ 72	$ 73
All Other Non-Labor	$ 94	$ 261	$ 112	$ 11	$ 181
Current Plan - Mgt. View	$17,879	$18,242	$18,389	$18,612	$18,982

Labor Expense

Salary Plan	2019 Average Headcount	2019 Base Salary	2019 Overtime and all Other Labor*	2019 TIA Labor Expense	2019 Total Salary & TIA Labor	2019 Labor Expense	2020 Labor Expense	2021 Labor Expense	2022 Labor Expense	2023 Labor Expense
Exempt	31	$ 4,554	$ -	$ 468	$ 5,022					
Non-Exempt	7	$ 452	$ -	$ 46	$ 499					
Subtotal	38	$ 5,007	$ -	$ 514	$ 5,520					
Co-ops / Interns	2	$ 82	$ -	$ 9	$ -					
Total	40	$ 5,088	$ -	$ 523	$ 5,520	$ 4,869	$ 5,026	$ 5,184	$ 5,296	$ 5,430

Note: Annual expense amounts are on an income statement basis and exclude balance sheet accounts.

Employee Headcount by Work Group

Department	May 31, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
Office of GC	2	2	2	2	2	2	2
Legal	19	21	21	21	21	21	21
Compliance	8	8	8	8	8	8	8
Federal Reg & Policy	2	3	3	3	3	3	3
External Affairs	3	4	4	4	4	4	4
Interns	2	2	2	2	2	2	2
Total	36	40	40	40	40	40	40

May 2018 Openings Include:
- Legal - 2 Corporate Attorneys
- Federal Reg & Policy Specialist
- Manager External Affairs

2017-2023 Headcount Totals & Changes

Employees	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
	Year-End						
TOTAL From Page 13	**36**	**40**	**40**	**40**	**40**	**40**	**40**
Prior Plan		40	40	40	40	40	
Change From Prior Plan		0	0	0	0	0	

Plan Risks

- Legal
  - — The plan does not include funds for material contingencies.
  - — Unfavorable developments in the Brown and Cane Run environmental litigation cases would place the 2019 budget under significant stress.
  - — The Company could become involved in a significant unanticipated legal issue, or could face an unanticipated shift in the timing of key steps in pending or planned legal matters.

Plan Risks

- Compliance
  - Possibility of significant new compliance or policy initiatives.
  - Expansion of Compliance Department's role under existing PHMSA compliance program.
  - Possibility of requirement to increase coordination on specific compliance topics, such as NERC.

Plan Risks

- Federal Regulation & Policy
  - — New FERC chairman and/or new commissioners could set aggressive agenda for major policy initiatives in which the Company must engage.
  - — Significant new regulations and policies that affect issues critical to the Company could be initiated (e.g., RTO membership, cyber-security, certain manifestations of federal/state jurisdictional questions).

Plan Risks

- External Affairs
  - Activity in the external affairs arena may result in additional activity/spending in other departments, including Corporate Communications, Legal, Regulatory and Environmental.

Human Resources
LG&E and KU Utilities
2019 Operating Plan

August 2018

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Plan Highlights

- Total OPEX increase of $3.76 million over the period of 2019-2023 relative to the 2018 HR Business Plan.
- Headcount is up 3 compared to last year's plan.
- The plan provides sufficient resources for HR to execute its mission of attracting, developing and retaining employees to meet business needs.
- Continued focus on talent development, career pathing, the mentoring program and the succession planning process to ensure employee engagement and a more qualified workforce.
- Continued focus on our knowledge retention plans ensuring solid action plans and regular updates occur.

Major Assumptions

- We will continue to see high levels of retirements – 139 YTD in 2018 with an average of 137 projected for each year of the plan.
- We will continue to see a significant volume of open positions in each year of the plan (364 filled in 2017).
- We will continue to see significant internal movement to roles with increasing responsibility (276 promotions YTD in 2018).
- We will continue to see changes in the health insurance market that will impact company costs.
- Upcoming union negotiations will be challenging, but we anticipate a favorable outcome with no work stoppages.

2017-2023 Annual O&M Expenses ($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
O&M Expenses Only:							
Labor	$ 5,456	$ 5,747	$ 6,235	$ 6,510	$ 6,691	$ 6,857	$ 7,053
Training, Travel, & Meals	$ 215	$ 305	$ 677	$ 669	$ 648	$ 638	$ 669
O/S Services	$ 306	$ 341	$ 364	$ 434	$ 353	$ 353	$ 434
Other Non-Labor	$ 214	$ 307	$ 334	$ 340	$ 335	$ 328	$ 340
Dues & Subscriptions	$ 39	$ 86	$ 86	$ 86	$ 86	$ 86	$ 86
HW/SW Maintenance	$ 2	$ 16	$ 18	$ 18	$ 18	$ 18	$ 18
Advertising	$ 3	$ 3	$ 5	$ 5	$ 5	$ 5	$ 5
Total O&M Expense - Mgmt. View	**$ 6,234**	**$ 6,805**	**$ 7,719**	**$ 8,062**	**$ 8,136**	**$ 8,285**	**$ 8,604**

O&M Annual Expense Reconciliation ($000)

	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
2018 Plan/Expectation	$7,049	$7,341	$7,416	$7,534	$7,742
Drivers:					
Labor	$ 156	$ 205	$ 211	$ 238	$ 235
Training, Travel, & Meals	$ 351	$ 354	$ 354	$ 354	$ 382
Outside Services	$ 145	$ 145	$ 145	$ 145	$ 223
All Other Non-labor	$ 18	$ 17	$ 11	$ 14	$ 22
Current Plan - Mgt. View	$7,719	$8,062	$8,136	$8,285	$8,604

2017-2023 Capital Expenditures
($000)

Item	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Equip Improvements	$ -	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20
Total Capital	$ -	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20
2018 Plan		$ 20	$ 20	$ 20	$ 20	$ 20	$ 20
Change		$ -	$ -	$ -	$ -	$ -	$ -

Labor Expense

Salary Plan	2019 Average Headcount	2019 Base Salary	2019 Overtime and all Other Labor*	2019 TIA Labor Expense	2019 Total Salary & TIA Labor	2019 Labor Expense	2020 Labor Expense	2021 Labor Expense	2022 Labor Expense	2023 Labor Expense
Exempt	45	$4,733	$ -	$ 486	$ 5,219					
Non-Exempt	14	$ 758	$ -	$ 78	$ 835					
Union / Non-Union Hourly	-	$ -	$ -	$ -	$ -					
Subtotal	59	$5,490	$ -	$ 564	$ 6,055					
Co-ops / Interns	2	$ 53	$ -	$ 6	$ 59					
Total	61	$5,544	$ -	$ 570	$ 6,114	$6,235	$6,510	$ 6,691	$6,857	$7,053

Note: Annual expense amounts are on an income statement basis and exclude balance sheet accounts.

Employee Headcount by Work Group

Work Group or Major Dept.	Jun 30, 2018 Actual	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2020	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2023
VP HR	2	2	2	2	2	2	2
Hincker	6	7	7	7	7	7	7
Industrial Relations	4	5	5	5	5	5	5
Gosman	4	5	5	5	5	5	5
Health &Wellness	4	4	4	4	4	4	4
Staffing	11	12	12	12	12	12	12
Compensation	3	3	3	3	3	3	3
Benefits	7	7	7	7	7	7	7
Johnson	6	6	6	6	6	6	6
Talent Management	4	4	4	4	4	4	4
HRIS	4	4	5	5	5	5	5
Inclusion	1	1	1	1	1	1	1
Total	56	60	61	61	61	61	61

2017-2023 Headcount Totals & Changes

Employees	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
		Year-End					
TOTAL From Page 9	**58**	**60**	**61**	**61**	**61**	**61**	**61**
Prior Plan		58	58	58	58	58	58
Change From Prior Plan		2	3	3	3	3	3

Plan Risks

- Company turnover increases beyond anticipated levels.
- Union negotiations do not go as anticipated.
- Changes in law and regulation impact our business.
- Medical plan self insurance could impact financial results.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(d)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

The utility's annual and monthly budget for the twelve (12) months preceding the filing date, the base period, and forecasted period.

Response:

See attached. Note that the attached does not reflect any impact from rate case activity beyond 2018.

Kentucky Utilities Company
Case No. 2018-00294
Annual and Monthly Budget for years 2017-2020
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended April 30, 2020

2017 Budget - Kentucky Utilities Company

Total Company

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Electric Operating Revenues	175,366,716	158,855,450	149,537,522	129,589,905	136,881,868	152,536,328	172,793,257	176,119,265	150,377,691	143,337,924	152,073,212	173,224,073	1,870,693,210
Total Operating Revenues	175,366,716	158,855,450	149,537,522	129,589,905	136,881,868	152,536,328	172,793,257	176,119,265	150,377,691	143,337,924	152,073,212	173,224,073	1,870,693,210
Operating Expenses													
Fuel for Electric Generation	49,350,784	43,528,578	39,477,807	36,762,625	38,738,673	46,158,781	49,483,871	50,361,583	38,870,421	38,798,011	41,810,982	44,951,834	518,293,951
Power Purchased	6,929,892	6,485,397	7,353,892	2,583,129	3,660,516	2,886,302	2,923,999	3,569,729	3,465,024	3,332,751	3,650,994	6,967,805	53,809,430
Other Operation Expenses	25,088,876	23,850,631	25,452,641	23,553,538	25,072,454	27,051,475	27,374,554	28,427,355	27,309,883	26,952,034	25,172,635	26,097,415	311,403,491
Maintenance	8,810,661	9,615,640	12,537,164	14,863,012	10,299,407	10,665,011	10,561,112	10,020,072	10,506,925	16,861,376	9,637,700	9,214,660	133,592,740
Depreciation & Amoritization Expense	20,322,981	20,336,645	20,350,175	20,376,467	20,412,838	20,453,256	25,579,756	25,683,310	25,808,108	25,896,087	26,017,741	26,193,967	277,431,331
Regulatory Debits	49,599	51,305	53,032	56,537	60,068	67,548	77,430	87,395	97,422	109,403	121,368	133,406	964,512
Current Income Taxes	20,698,176	16,906,151	12,367,737	7,705,055	10,509,913	12,728,352	17,578,233	18,040,229	12,376,613	7,693,454	13,250,063	18,329,647	168,183,623
Property and Other Taxes	3,542,100	3,537,919	3,545,176	3,539,865	3,544,888	3,539,638	3,535,477	3,547,113	3,539,303	3,548,093	3,541,603	3,532,826	42,494,000
Total Operating Expenses	134,793,069	124,312,267	121,137,624	109,440,228	112,298,757	123,550,363	137,114,430	139,736,785	121,973,700	123,191,209	123,203,085	135,421,559	1,506,173,078
Net Operating Income	40,573,647	34,543,183	28,399,898	20,149,677	24,583,111	28,985,965	35,678,827	36,382,480	28,403,991	20,146,715	28,870,127	37,802,514	364,520,132
AFUDC - Equity	16,857	19,033	21,643	24,506	26,800	29,270	32,911	36,960	41,230	44,183	46,926	49,556	389,875
Other Income less deductions	(107,337)	113,542	55,129	89,543	111,248	104,695	140,505	119,875	116,050	102,300	57,170	85,369	988,089
Income before Interest Charges	40,483,167	34,675,758	28,476,669	20,263,726	24,721,159	29,119,930	35,852,243	36,539,315	28,561,271	20,293,198	28,974,223	37,937,438	365,898,096
Interest Charges	8,001,544	7,927,192	7,981,390	7,985,792	8,013,652	8,001,042	8,007,201	7,985,199	7,971,541	8,001,053	7,996,731	8,019,670	95,892,007
Net Income	32,481,623	26,748,566	20,495,279	12,277,934	16,707,507	21,118,889	27,845,042	28,554,116	20,589,730	12,292,145	20,977,492	29,917,768	270,006,089

Kentucky Utilities Company
Case No. 2018-00294
Annual and Monthly Budget for years 2017-2020
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended April 30, 2020

2018 Budget - Kentucky Utilities Company

Total Company	January	February	March	April	May	June	July	August	September	October	November	December	Budgeted Base Period 12/31/18[1]	Total 12 Months Preceding Filing Date[2]
INCOME STATEMENT														
Operating Revenues														
Electric Operating Revenues	168,070,455	150,753,857	143,090,445	124,569,942	130,705,079	146,248,462	156,156,135	158,883,757	137,228,565	130,260,843	137,661,027	158,935,263	1,742,563,830	1,797,491,031
Total Operating Revenues	168,070,455	150,753,857	143,090,445	124,569,942	130,705,079	146,248,462	156,156,135	158,883,757	137,228,565	130,260,843	137,661,027	158,935,263	1,742,563,830	1,797,491,031
Operating Expenses														
Fuel for Electric Generation	45,294,400	39,121,087	37,255,026	32,018,265	35,247,378	41,491,697	44,716,592	45,640,103	35,167,679	33,722,747	36,180,842	40,166,463	466,022,279	485,215,795
Power Purchased	7,487,692	6,260,687	5,975,225	3,641,077	2,954,690	3,271,876	2,834,225	2,739,957	3,624,233	3,770,069	3,897,692	6,810,877	53,268,299	52,582,004
Other Operation Expenses	26,617,645	23,945,118	25,157,823	24,065,313	24,967,373	25,340,825	26,382,360	27,194,533	24,975,663	26,105,678	24,100,392	25,848,547	304,701,270	309,202,957
Maintenance	9,175,950	9,915,577	14,784,962	17,370,953	11,525,718	10,918,750	10,931,246	10,683,154	11,235,890	16,455,398	12,159,970	9,646,049	144,803,617	141,526,971
Depreciation & Amoritization Expense	22,765,681	22,765,687	22,786,181	22,878,834	22,987,202	23,064,201	23,111,304	23,180,420	23,284,148	23,342,293	23,429,149	23,695,162	277,290,261	287,455,412
Regulatory Debits	214,021	229,518	254,447	290,305	341,487	384,320	447,230	497,625	555,082	612,424	640,622	659,487	5,126,568	3,120,551
Current Income Taxes	11,367,643	9,324,640	3,939,673	3,045,756	5,173,789	5,145,713	9,046,763	9,368,064	4,278,776	3,489,935	6,309,108	7,756,090	78,245,949	108,061,816
Property and Other Taxes	3,742,763	3,738,743	3,744,438	3,738,106	3,743,709	3,739,198	3,747,056	3,752,520	3,744,001	3,753,885	3,746,203	3,738,377	44,929,002	44,108,360
Total Operating Expenses	126,665,795	115,301,056	113,897,775	107,048,608	106,941,345	113,356,579	121,216,776	123,056,376	106,865,473	111,252,429	110,463,979	118,321,052	1,374,387,244	1,431,273,865
Net Operating Income	41,404,660	35,452,801	29,192,670	17,521,333	23,763,734	32,891,883	34,939,358	35,827,381	30,363,092	19,008,414	27,197,048	40,614,212	368,176,586	366,217,167
AFUDC - Equity	19,166	23,683	28,485	33,382	38,742	44,727	50,985	55,104	55,538	57,346	62,174	62,414	531,746	476,169
Other Income less deductions	(162,539)	83,345	113,079	78,549	136,564	112,223	113,748	130,769	131,012	146,064	148,299	19,112	1,050,226	966,628
Income before Interest Charges	41,261,287	35,559,829	29,334,234	17,633,264	23,939,041	33,048,834	35,104,091	36,013,254	30,549,641	19,211,823	27,407,521	40,695,738	369,758,558	367,659,963
Interest Charges	8,400,761	8,342,974	8,426,167	8,526,111	8,629,126	8,645,951	8,631,207	8,592,274	8,618,274	8,731,731	8,787,041	8,837,331	103,168,948	100,183,566
Net Income	32,860,526	27,216,855	20,908,067	9,107,153	15,309,915	24,402,883	26,472,883	27,420,980	21,931,368	10,480,093	18,620,480	31,858,406	266,589,610	267,476,397

Budgeted Base Period 12/31/18[1] - Sum of January through December of the 2018 Budget.

Total 12 Months Preceding Filing Date[2] - Sum of September through December of the 2017 Budget plus January through August of the 2018 Budget.

Kentucky Utilities Company
Case No. 2018-00294
Annual and Monthly Budget for years 2017-2020
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended April 30, 2020

2019 Budget - Kentucky Utilities Company

Total Company

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Electric Operating Revenues	168,682,248	146,566,567	139,171,911	125,938,971	136,470,797	140,346,051	152,868,712	156,017,814	137,319,036	128,105,686	137,624,726	153,564,130	1,722,676,652
Total Operating Revenues	168,682,248	146,566,567	139,171,911	125,938,971	136,470,797	140,346,051	152,868,712	156,017,814	137,319,036	128,105,686	137,624,726	153,564,130	1,722,676,652
Operating Expenses													
Fuel for Electric Generation	44,680,960	36,392,683	34,392,915	31,978,901	36,037,970	36,801,352	40,615,883	42,433,793	34,052,082	31,219,494	32,369,458	36,777,632	437,753,124
Power Purchased	8,216,887	6,491,146	5,966,148	4,265,908	3,661,651	2,824,756	2,792,377	3,070,717	3,122,186	3,471,700	6,447,651	6,943,534	57,274,660
Other Operation Expenses	25,424,658	23,049,139	23,827,489	23,794,455	24,867,253	24,454,345	26,590,028	26,482,172	25,692,645	26,075,073	23,307,277	24,350,262	297,914,796
Maintenance	8,949,540	12,093,555	14,559,179	15,440,282	11,772,852	10,439,333	11,252,441	10,157,321	11,895,067	16,770,542	13,698,086	10,067,252	147,095,450
Depreciation & Amoritization Expense	23,923,917	23,789,324	23,672,251	23,604,097	29,026,005	29,427,851	29,572,455	29,616,828	29,658,973	29,723,394	29,822,905	30,130,902	331,968,902
Regulatory Debits	811,880	869,293	925,578	1,011,985	700,169	727,339	747,067	766,470	781,229	793,104	803,866	840,293	9,778,273
Current Income Taxes	10,904,830	7,725,935	(304,497)	1,872,787	4,064,047	3,939,292	6,864,863	7,416,160	(21,537)	1,522,647	4,273,479	4,527,556	52,785,561
Property and Other Taxes	3,976,760	3,971,925	3,977,393	3,974,066	3,970,793	3,966,557	3,977,008	3,980,680	3,975,306	3,976,899	3,969,934	3,972,780	47,690,099
Total Operating Expenses	126,889,432	114,382,999	107,016,457	105,942,481	114,100,740	112,580,824	122,412,122	123,924,141	109,155,951	113,552,852	114,692,655	117,610,212	1,382,260,867
Net Operating Income	41,792,817	32,183,568	32,155,454	19,996,490	22,370,057	27,765,227	30,456,590	32,093,673	28,163,085	14,552,834	22,932,071	35,953,919	340,415,785
AFUDC - Equity	4,619	1,654	2,414	2,782	433	464	617	737	540	460	304	145	15,169
Other Income less deductions	(192,789)	72,032	137,281	132,776	149,173	121,114	142,067	154,282	125,204	149,475	160,305	40,623	1,191,543
Income before Interest Charges	41,604,646	32,257,254	32,295,149	20,132,048	22,519,663	27,886,805	30,599,275	32,248,692	28,288,828	14,702,769	23,092,680	35,994,686	341,622,497
Interest Charges	8,769,485	8,722,403	8,825,392	8,927,769	9,894,551	9,548,758	9,556,184	9,534,957	9,628,193	9,721,901	9,826,590	9,894,971	112,851,155
Net Income	32,835,161	23,534,851	23,469,756	11,204,279	12,625,112	18,338,047	21,043,091	22,713,735	18,660,635	4,980,868	13,266,090	26,099,715	228,771,342

Kentucky Utilities Company
Case No. 2018-00294
Annual and Monthly Budget for years 2017-2020
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended April 30, 2020

2020 Budget - Kentucky Utilities Company

Total Company	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	Test Year 4/30/2020
INCOME STATEMENT														
Operating Revenues														
Electric Operating Revenues	172,368,610	148,891,251	144,743,036	127,767,846	135,475,677	141,276,096	154,196,679	156,282,716	137,408,788	128,910,081	137,929,328	153,594,337	1,738,844,444	1,736,087,697
Total Operating Revenues	172,368,610	148,891,251	144,743,036	127,767,846	135,475,677	141,276,096	154,196,679	156,282,716	137,408,788	128,910,081	137,929,328	153,594,337	1,738,844,444	1,736,087,697
Operating Expenses														
Fuel for Electric Generation	43,050,715	34,673,541	29,913,455	30,022,359	34,559,552	36,823,893	41,372,212	42,274,944	33,375,398	31,217,572	34,532,348	37,789,227	429,605,215	427,967,733
Power Purchased	7,213,143	5,280,814	9,934,094	3,273,573	3,109,495	2,729,801	2,503,503	2,464,185	3,095,802	3,593,216	4,177,118	5,894,473	53,269,218	58,036,196
Other Operation Expenses	26,652,080	24,511,991	25,240,963	25,160,222	25,128,512	26,256,956	27,409,614	26,786,394	26,861,031	26,431,159	24,539,440	25,497,128	310,475,490	303,384,311
Maintenance	9,491,236	9,758,809	16,763,557	17,531,585	12,003,360	11,511,915	11,722,110	10,350,287	11,539,307	15,478,853	13,649,458	10,114,142	149,914,619	149,598,081
Depreciation & Amoritization Expense	30,370,817	30,344,278	30,420,811	30,573,721	30,700,786	30,830,382	30,896,874	30,897,865	30,903,433	30,978,882	31,104,235	30,979,425	369,001,509	358,688,939
Regulatory Debits	847,773	858,285	869,891	891,800	914,685	940,954	966,241	985,427	1,002,268	1,010,993	1,016,993	1,027,091	11,332,400	9,627,285
Current Income Taxes	10,108,819	7,325,757	(3,054,907)	476,478	3,088,561	3,124,735	6,220,466	7,034,614	(1,547,512)	1,258,544	3,443,419	3,167,176	40,646,149	47,442,654
Property and Other Taxes	4,145,605	4,140,922	4,152,721	4,143,119	4,140,233	4,143,588	4,148,854	4,148,762	4,148,937	4,150,991	4,145,046	4,147,339	49,756,116	48,372,323
Total Operating Expenses	131,880,187	116,894,396	114,240,585	112,072,857	113,645,184	116,362,223	125,239,875	124,942,477	109,378,663	114,120,210	116,608,057	118,616,001	1,414,000,716	1,403,117,522
Net Operating Income	40,488,423	31,996,855	30,502,451	15,694,989	21,830,492	24,913,873	28,956,805	31,340,238	28,030,124	14,789,870	21,321,271	34,978,336	324,843,728	332,970,175
AFUDC - Equity	55	24	27	37	47	54	69	66	53	37	31	32	532	3,842
Other Income less deductions	(217,374)	47,774	110,886	108,469	155,372	117,665	144,854	156,288	120,410	153,482	162,915	40,824	1,101,566	1,091,998
Income before Interest Charges	40,271,104	32,044,653	30,613,363	15,803,496	21,985,911	25,031,592	29,101,728	31,496,593	28,150,587	14,943,390	21,484,218	35,019,192	325,945,825	334,066,015
Interest Charges	9,830,147	9,710,073	9,774,511	9,907,167	10,038,819	10,046,625	9,994,755	9,929,219	8,763,800	10,753,362	10,712,625	10,767,894	120,228,996	116,828,003
Net Income	30,440,957	22,334,580	20,838,852	5,896,328	11,947,092	14,984,967	19,106,973	21,567,374	19,386,787	4,190,028	10,771,592	24,251,298	205,716,829	217,238,012

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(e)
Sponsoring Witness: Paul W. Thompson

Description of Filing Requirement:

A statement of attestation signed by the utility's chief officer in charge of Kentucky operations, which shall provide:

1. *That the forecast is reasonable, reliable, made in good faith, and that all basic assumptions used in the forecast have been identified and justified;*
2. *That the forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management, or an identification and explanation for differences that exist, if applicable; and*
3. *That productivity and efficiency gains are included in the forecast.*

Response:

See attached.

STATEMENT OF ATTESTATION SIGNED BY THE UTILITY'S CHIEF OFFICER IN CHARGE OF KENTUCKY OPERATIONS

1. The forecast presented in this rate application is reasonable, reliable, made in good faith, and all basic assumptions used in the forecast have been identified and justified;

2. The forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management, except for the differences that have been identified and explained in the filing requirements and schedules thereto; and

3. Productivity and efficiency gains are included in the forecast.

Paul Thompson

PAUL W. THOMPSON
Chief Executive Officer and President of
Louisville Gas and Electric Company and
Kentucky Utilities Company

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of September, 2018.

My Commission Expires:
Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022
(SEAL)

Judy Schooler
Notary Public

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(f)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

For each major construction project that constitutes five (5) percent or more of the annual construction budget within the three (3) year forecast, the following information shall be filed:

1. *The date the project was started or estimated starting date;*
2. *The estimated completion date;*
3. *The total estimated cost of construction by year exclusive and inclusive of allowance for funds used during construction ("AFUDC") or interest during construction credit; and*
4. *The most recent available total costs incurred exclusive and inclusive of AFUDC or interest during construction credit.*

Response:

See attached.

Kentucky Utilities Company
Case No. 2018-00294
Fully Forecasted Test Period
Summary of Capital Construction Forecast which Constitute More than five (5%) of the Total and all other Projects

Year 2018

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 6/30/18 Without AFUDC	AFUDC	Inception-to-Date 6/30/18 With AFUDC	Inception-to-Date 12/31/17 With AFUDC	Actual Start Date	Expected Start Date	Expected Completion Date
Ghent	GH Process Water	N/A	$ 86,762,337	$ -	$ 86,762,337	$ 86,716,222	$ -	$ 86,716,222	$ 40,839,874	Aug-16		Dec-19
	All Other Projects < 5%		$ 547,747,047	$ 617,078	$ 548,364,125	$ 1,928,490,985	$ 2,258,556 -	$ 1,930,749,541	$ 1,723,114,878			

Year 2019

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 6/30/18 Without AFUDC	AFUDC	Inception-to-Date 6/30/18 With AFUDC	Inception-to-Date 12/31/17 With AFUDC	Actual Start Date	Expected Start Date	Expected Completion Date
				$ -	$ -		$ -	$ -	$ -			
	All Other Projects < 5%		$ 610,191,842	$ -	$ 610,191,842	$ 614,544,848	$ 956,931	$ 615,501,779	$ 479,816,013			

Year 2020

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 6/30/18 Without AFUDC	AFUDC	Inception-to-Date 6/30/18 With AFUDC	Inception-to-Date 12/31/17 With AFUDC	Actual Start Date	Expected Start Date	Expected Completion Date
	All Other Projects < 5%		$ 503,198,484	$ -	$ 503,198,484	$ 406,499,317	$ 200,827	$ 406,700,144	$ 348,248,137			

Year 2021

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 6/30/18 Without AFUDC	AFUDC	Inception-to-Date 6/30/18 With AFUDC	Inception-to-Date 12/31/17 With AFUDC	Actual Start Date	Expected Start Date	Expected Completion Date
NA	Priority Transmission Line Replacement	N/A	$ 40,388,704	$ -	$ 40,388,704		$ -	$ -	$ -		Jan-21	Dec-21
	All Other Projects < 5%		$ 476,707,370	$ -	$ 476,707,370	$ 343,950,699	$ -	$ 343,950,699	$ 306,524,197			

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(g)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

For all construction projects that constitute less than five (5) percent of the annual construction budget within the three (3) year forecast, the utility shall file an aggregate of the information requested in paragraph (f)3 and 4 of this subsection.

Response:

See KU's response to Filing Requirement 807 KAR 5:001 Section 16(7)(f)[Tab No. 19].

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

Response:

See KU’s responses to Tab Nos. 22-38.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(1)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

1. *Operating income statement (exclusive of dividends per share or earnings per share);*

Response:

See attached. Note that the attached does not reflect any impact from rate case activity beyond 2018.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Income Statements 2018 - 2021
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended April 30, 2020

Kentucky Utilities Company - Total Company

	2018	2019	2020	2021
	$	$	$	$
INCOME STATEMENT				
Operating Revenues				
Electric Operating Revenues	1,744,297,194	1,722,676,652	1,738,844,444	1,749,542,538
Total Operating Revenues	1,744,297,194	1,722,676,652	1,738,844,444	1,749,542,538
Operating Expenses				
Fuel for Electric Generation	489,452,786	437,753,124	429,605,215	438,840,384
Power Purchased	48,697,920	57,274,660	53,269,218	58,259,919
Other Operation Expenses	289,884,971	297,914,796	310,475,490	315,870,025
Maintenance	145,817,943	147,095,450	149,914,619	150,460,153
Depreciation & Amortization Expense	275,782,393	331,968,902	369,001,509	373,140,292
Regulatory Debits	5,423,562	9,778,273	11,332,400	13,079,197
Current Income Taxes	73,583,037	52,785,561	40,646,149	34,826,674
Property and Other Taxes	44,773,917	47,690,099	49,756,116	52,558,670
Amortization of Investment Tax Credit	-	-	-	-
Loss (Gain) from Diposition of Allowances	(27,813)	-	-	-
Total Operating Expenses	1,373,388,717	1,382,260,867	1,414,000,716	1,437,035,313
Net Operating Income	370,908,476	340,415,785	324,843,728	312,507,225
AFUDC - Equity	367,186	15,169	532	-
Other Income less deductions	1,324,648	1,191,543	1,101,566	1,121,584
Income before Interest Charges	372,600,310	341,622,497	325,945,825	313,628,809
Interest Charges	100,748,858	112,851,155	120,228,996	131,747,103
Net Income	271,851,452	228,771,342	205,716,829	181,881,707

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(2)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

2. Balance sheet;

Response:

See attached. Note that the attached does not reflect any impact from rate case activity beyond 2018.

Kentucky Utilities Company
Case No. 2018-00294
Balance Sheet - Total Company
Calendar Years 2018-2021

	2018	2019	2020	2021
Kentucky Utilities Company - Total	$	$	$	$
ASSETS AND OTHER DEBITS				
UTILITY PLANT				
Gross Utility Plant	10,104,713,542	10,439,454,982	10,702,076,554	11,102,636,884
Accumulated Provision for Depreciation and Amortization	(3,457,985,896)	(3,560,132,250)	(3,759,507,335)	(4,062,849,546)
Total Utility Net Plant	**6,646,727,646**	**6,879,322,732**	**6,942,569,219**	**7,039,787,338**
INVESTMENTS				
Investment in Subsidiary Companies	250,000	250,000	250,000	250,000
Net Nonutility property	178,714	178,714	178,714	178,714
Other Investments	18,227,237	25,831,926	34,120,134	43,092,422
Total other Property and Investments	**18,655,951**	**26,260,640**	**34,548,848**	**43,521,136**
CURRENT AND ACCRUED ASSETS				
Cash	5,061,030	5,061,030	5,061,030	5,061,030
Special Deposits and Temporary Cash Investments	0	(0)	(0)	(0)
Accounts Receivable - Less Reserves	269,637,640	267,349,079	266,882,586	266,597,782
Accounts Receivable from Associated Companies	2,154,539	4,424,917	6,133,612	9,719,610
Inventories	125,530,709	128,292,753	129,136,515	139,049,243
Prepayments	16,300,802	15,324,925	15,498,209	14,753,915
Other Current and Accrued Assets				
Total Current and Accrued Assets	**418,684,720**	**420,452,705**	**422,711,952**	**435,181,580**
DEFERRED DEBITS AND OTHER				
Unamortized Debt Expenses	24,990,497	26,199,995	27,571,946	29,494,002
Accumulated Deferred Income Tax Asset	349,065,730	349,065,730	349,065,730	349,065,730
Regulatory Assets	424,134,542	437,673,716	442,044,323	437,806,654
Miscellaneous Deferred Debits	62,052,673	66,888,930	55,289,256	55,025,999
Total Deferred Debits & Other	**860,243,442**	**879,828,371**	**873,971,255**	**871,392,386**
TOTAL ASSETS	**7,944,311,758**	**8,205,864,448**	**8,273,801,274**	**8,389,882,439**
LIABILITIES AND OTHER CREDITS				
PROPRIETARY CAPITAL				
Common and Preferred Stock Issued	308,139,978	308,139,978	308,139,978	308,139,978
Common Stock Expense	(321,289)	(321,289)	(321,289)	(321,289)
Paid-in-capital	695,148,639	810,713,213	900,588,179	984,810,881
Retained Earnings	1,889,722,949	1,913,675,199	1,890,550,214	1,890,709,702
Other Comprehensive Income	0	0	0	0
Total Proprietary Capital	**2,892,690,277**	**3,032,207,101**	**3,098,957,083**	**3,183,339,272**
Total Long-Term Debt	**2,333,824,308**	**2,634,362,953**	**2,584,870,864**	**2,585,249,528**
TOTAL CAPITALIZATION	**5,226,514,584**	**5,666,570,054**	**5,683,827,946**	**5,768,588,801**
CURRENT AND ACCRUED LIABILITIES				
Notes Payable	256,558,345	80,985,019	190,968,201	267,271,862
Accounts Payable	146,521,000	132,850,721	128,387,000	125,371,331
Accounts Payable to Associated Companies	48,206,048	48,708,845	49,403,296	52,345,815
Customer Deposits	30,898,393	30,898,393	30,898,393	30,898,393
Taxes Accrued	18,373,835	20,061,024	20,924,216	22,162,078
Interest Accrued	16,101,169	17,651,375	21,990,047	22,317,832
Dividends Payable Affiliate				
Miscellaneous Current Liabilities	24,085,032	29,312,313	28,005,956	27,266,345
Total Current and Accrued Liabilities	**540,743,823**	**360,467,690**	**470,577,110**	**547,633,656**
DEFERRED CREDITS				
Accumulated Deferred Income Tax Liability	1,091,307,923	1,159,970,850	1,184,033,934	1,199,527,802
Investment Tax Credits	91,624,046	89,615,620	87,719,884	85,824,148
Regulatory Liabilities	763,002,606	723,087,764	693,423,173	664,380,714
Customer Advances for Construction	980,981	980,981	980,981	980,981
Asset Retirement Obligations	196,181,958	157,708,631	115,140,694	93,945,350
Other Deferred Credits	1,739,959	1,739,959	1,739,959	1,739,959
Miscellaneous Long Term Liabilities	3,198,333	21,251,505	16,574,160	12,231,627
Accumulated Provision for Post Retirement Benefits	29,017,547	24,471,393	19,783,433	15,029,402
Total Deferred Credits	**2,177,053,352**	**2,178,826,704**	**2,119,396,219**	**2,073,659,983**
TOTAL LIABILITIES AND STOCKHOLDER EQUITY	**7,944,311,758**	**8,205,864,448**	**8,273,801,274**	**8,389,882,439**

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(3)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

3. Statement of cash flows;

Response:

See attached. Note that the attached does not reflect any impact from rate case activity beyond 2018.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Cash Flow Statements 2018 - 2021
Base Period: Twelve Months Ended December 31, 2018
Forecasted Test Period: Twelve Months Ended April 30, 2020

Kentucky Utilities Company Cash Flow Statement	**2018**	**2019**	**2020**	**2021**
	$	$	$	$
Cash Flows from Operating Activities				
Net Income	271,851,452	228,771,342	205,716,829	181,881,707
Adjustments to reconcile net income to net cash provided by (used in) operating activities				
Depreciation	281,205,955	341,747,175	380,333,910	386,219,489
Amortization	(7,282,723)	(6,295,607)	(84,661)	(851,406)
Defined benefit plans - Expense	175,695	(993,770)	(1,537,134)	(1,943,110)
Deferred income taxes and investment tax credits	53,361,394	44,915,477	(4,039,180)	(10,497,349)
Change in current assets and current liabilities				
Accounts receivable	247,890	18,183	(1,242,202)	(3,301,194)
Inventories	(3,207,991)	(6,887,550)	1,631,180	(8,084,800)
Other current assets	(333,085)	(904,235)	(1,265,911)	(950,286)
Regulatory assets and liabilities	(3,121,500)	(6,953,666)	(1,672,592)	(1,785,615)
Accounts payable	8,413,861	(2,176,183)	(1,503,619)	642,599
Taxes accrued	(721,026)	1,069,535	288,221	707,052
Interest accrued	(60,071)	1,550,205	4,338,673	327,784
Other current liabilities	26,372,107	(898,776)	(822,656)	(901,132)
Other operating activities				
ARO expenditures	(51,763,413)	(61,317,946)	(52,210,417)	(28,859,978)
Defined benefit plans - funding	(54,374,115)	(5,159,065)	(5,251,108)	(5,338,938)
Other	(1,159,303)	-	-	-
Net cash provided by operating activities	519,605,128	526,485,120	522,679,332	507,264,822
Cash Flows from Investing Activities				
Expenditures for property, plant and equipment	(602,947,975)	(558,582,277)	(440,320,666)	(486,068,966)
Net cash used in investing activities	(602,947,975)	(558,582,277)	(440,320,666)	(486,068,966)
Cash Flows from Financing Activities				
Issuance of long-term debt	-	300,000,000	450,000,000	-
Net increase (decrease) in short-term debt	211,600,919	(175,573,325)	109,983,181	76,303,661
Contributions from PPL	111,290,556	115,564,574	89,874,966	84,222,702
Payment of common stock dividends to parent	(239,948,656)	(204,819,092)	(228,841,814)	(181,722,219)
Retirement of long-term debt	(8,927,000)	-	(500,000,000)	-
Other financing activities	(353,944)	(3,075,000)	(3,375,000)	0
Net Cash provided by financing activities	73,661,875	32,097,157	(82,358,666)	(21,195,856)
Net Increase (Decrease) in Cash and Cash Equivalents	(9,680,972)	(0)	0	0
Cash and Cash Equivalents at Beginning of Period	14,742,002	5,061,030	5,061,030	5,061,030
Cash and Cash Equivalents at End of Period	5,061,030	5,061,030	5,061,030	5,061,030

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(4)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

4. Revenue requirements necessary to support the forecasted rate of return;

Response:

See attached. Note that the attached does not reflect any impact from rate case activity beyond 2018.

KENTUCKY UTILITIES COMPANY
CASE NO. 2018-00294
OVERALL FINANCIAL SUMMARY
FORECAST PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31,

		FORECASTED			
		2018	2019	2020	2021
LINE NO.	DESCRIPTION	JURISDICTIONAL REVENUE REQUIREMENT	JURISDICTIONAL REVENUE REQUIREMENT	JURISDICTIONAL REVENUE REQUIREMENT	JURISDICTIONAL REVENUE REQUIREMENT
		$	$	$	$
1	CAPITALIZATION ALLOCATED TO KENTUCKY JURISDICTION (a)	3,744,998,304	4,009,196,613	4,208,840,073	4,365,077,931
2	ADJUSTED OPERATING INCOME	258,779,791	231,115,000	220,387,476	211,457,995
3	EARNED RATE OF RETURN (2 / 1)	6.91%	5.76%	5.24%	4.84%
4	REQUIRED RATE OF RETURN	7.43%	7.54%	7.61%	7.75%
5	REQUIRED OPERATING INCOME (1 x 4)	278,356,066	302,338,961	320,164,468	338,323,112
6	OPERATING INCOME DEFICIENCY (5 - 2)	19,576,275	71,223,962	99,776,991	126,865,117
7	GROSS REVENUE CONVERSION FACTOR	1.339356	1.339356	1.339356	1.339356
8	REVENUE DEFICIENCY (6 x 7)	26,219,603	95,394,248	133,636,923	169,917,570
9	ADJUSTED OPERATING REVENUES	1,409,211,753	1,425,811,376	1,448,829,250	1,443,603,681
10	REVENUE REQUIREMENTS (8 + 9)	1,435,431,356	1,521,205,624	1,582,466,173	1,613,521,251

(a) 2019-2021 - 13 months average

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(5)
Sponsoring Witness: David S. Sinclair

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

5. Load forecast including energy and demand (electric);

Response:

Table 1: KU Energy (GWh)

RETAIL				
Rate	**2018***	**2019**	**2020**	**2021**
AES	140	133	131	128
EV Charging	0	0	0	0
FLS	635	622	622	622
GS	1,815	1,743	1,734	1,727
Outdoor School Lighting	0	0	0	0
PS-Pri	143	144	144	144
PS-Sec	1,879	1,814	1,800	1,793
RS	6,229	5,957	5,954	5,917
RTOD	1	1	1	1
RTS	1,481	1,467	1,479	1,479
TOD-Pri	4,029	4,027	4,031	4,012
TOD-Sec	1,807	1,833	1,845	1,851
Lighting	126	126	125	122
Retail Total	18,285	17,867	17,866	17,796
WHOLESALE				
Rate	**2018**	**2019**	**2020**	**2021**
Municipal - Departing	1,416	454	0	0
Municipal - Remaining	418	421	425	427
Wholesale Total	1,834	875	425	427
Grand Total	**20,119**	**18,742**	**18,291**	**18,223**

*2018 includes 6 months of actual and 6 months of forecasted data

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(5)
Sponsoring Witness: David S. Sinclair

Table 2: KU Demand

RETAIL						
Rate	**Period**	**Unit**	**2018***	**2019**	**2020**	**2021**
FLS	BASE	MVA	2,432	2,388	2,388	2,388
FLS	INTERMEDIATE	MVA	2,404	2,381	2,381	2,381
FLS	PEAK	MVA	1,657	1,646	1,646	1,646
OSL	BASE	MW	7	5	5	5
OSL	PEAK	MW	2	1	1	1
PS-Pri	BASE	MW	420	422	423	421
PS-Sec	BASE	MW	5,651	5,488	5,473	5,438
RTS	BASE	MVA	3,387	3,352	3,363	3,365
RTS	INTERMEDIATE	MVA	3,051	2,977	3,003	3,012
RTS	PEAK	MVA	3,032	2,981	3,007	3,015
TOD-Pri	BASE	MVA	10,367	10,326	10,323	10,287
TOD-Pri	INTERMEDIATE	MVA	8,749	8,638	8,656	8,625
TOD-Pri	PEAK	MVA	8,630	8,519	8,537	8,507
TOD-Sec	BASE	MW	5,589	5,587	5,617	5,634
TOD-Sec	INTERMEDIATE	MW	4,287	4,173	4,190	4,202
TOD-Sec	PEAK	MW	4,180	4,068	4,084	4,096
WHOLESALE						
Rate	**Period**	**Unit**	**2018**	**2019**	**2020**	**2021**
Municipal - Departing	BASE	MW	2,799	864	0	0
Municipal - Remaining	BASE	MW	804	811	819	824

*2018 includes 6 months of actual and 6 months of forecasted data

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(6)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

6. Access line forecast (telephone);

Response:

Not applicable to KU's Application.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(7)
Sponsoring Witness: David S. Sinclair

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

7. Mix of generation (electric);

Response:

See attached.

GWh[1]	**2018**[2]	**2019**	**2020**	**2021**
Coal				
Brown 1	320	33	N/A	N/A
Brown 2	661	69	N/A	N/A
Brown 3	1,260	690	700	735
Ghent 1	2,898	2,724	2,679	2,359
Ghent 2	3,241	2,866	3,233	3,094
Ghent 3	2,276	2,277	2,279	2,159
Ghent 4	2,714	2,571	2,285	2,349
Mill Creek 1	N/A	N/A	N/A	N/A
Mill Creek 2	N/A	N/A	N/A	N/A
Mill Creek 3	N/A	N/A	N/A	N/A
Mill Creek 4	N/A	N/A	N/A	N/A
OVEC	243	238	230	229
Trimble County 1	N/A	N/A	N/A	N/A
Trimble County 2	2,385	2,685	2,772	2,720
SCCT				
Bluegrass/EKPC[3]	N/A	N/A	N/A	N/A
Brown 5	48	71	56	58
Brown 6	87	74	59	71
Brown 7	81	40	42	42
Brown 8	28	19	15	11
Brown 9	20	26	20	16
Brown 10	28	30	31	25
Brown 11	10	13	12	9
Cane Run 11	N/A	N/A	N/A	N/A
Haefling	0	1	0	0
Paddy’s Run 11	N/A	N/A	N/A	N/A
Paddy’s Run 12	N/A	N/A	N/A	N/A
Paddy’s Run 13	52	69	64	56
Trimble Co 05	135	265	244	212
Trimble Co 06	123	190	183	157
Trimble Co 07	142	120	124	105
Trimble Co 08	117	55	52	28
Trimble Co 09	99	34	24	78
Trimble Co 10	26	15	17	18
Zorn 1	N/A	N/A	N/A	N/A
NGCC				
Cane Run 7	3,901	4,120	3,807	4,123
Hydro				
Dix Dam	113	82	82	82
Ohio Falls	N/A	N/A	N/A	N/A
Solar				
Brown Solar	11	11	11	11
Total Coal	15,997	14,152	14,178	13,645
Total SCCT	996	1,025	941	887
Total NGCC	3,901	4,120	3,807	4,123
Total Hydro	113	82	82	82
Total Solar	11	11	11	11
Grand Total	21,018	19,389	19,019	18,747

[1] Generation volumes reflect KU’s ownership share of the unit. “N/A” is shown for units with no KU ownership share.
[2] 2018 generation volumes reflect actual generation for January-June and forecast generation for July-December.
[3] Capacity Purchase and Tolling Agreement with Bluegrass Generation/EKPC

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(8)
Sponsoring Witness: Lonnie E. Bellar

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

8. Mix of gas supply (gas);

Response:

Not applicable to KU's Application.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(9)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

9. Employee level;

Response:

See attached.

Kentucky Utilities Company
Case No. 2018-00294
Employee Level
Years 2018-2021

	Estimated Number of Full-Time KU Employees at 12/31
2018	916
2019	911
2020	909
2021	906

	Estimated Number of Total KU Employees at 12/31^
2018	929
2019	925
2020	923
2021	920

	Estimated Number of Full-Time LG&E and KU Services Company (LKS) Employees at 12/31*
2018	1618
2019	1628
2020	1633
2021	1630

	Estimated Number of Total LG&E and KU Services Company (LKS) Employees at 12/31*^
2018	1708
2019	1715
2020	1720
2021	1717

*LGE and KU Services employees serve LGE, KU, and LGE & KU Energy LLC. Number of LGE and KU Services employees is not allocated; however, labor dollars are allocated via the Cost Allocation Manual (CAM).

^ Totals include part-time employees, cooperatives and interns.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(10)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

10. Labor cost changes;

Response:

See attached.

Kentucky Utilities
Case No. 2018-00294
Labor Cost
Years 2018-2021

Forecast Year	Total Wages	Amount Over Previous Year	Percentage Over Previous Year
2018	$ 192,133,284		
2019	$ 200,055,176	$ 7,921,892	4.12%
2020	$ 207,237,635	$ 7,182,459	3.59%
2021	$ 210,302,969	$ 3,065,334	1.48%

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(11)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

11. Capital structure requirements;

Response:

See attached.

KENTUCKY UTILITIES COMPANY
CASE NO. 2018-00294
CAPITAL STRUCTURE REQUIREMENT
AS OF DECEMBER 31

		FORECASTED							
		2018		2019		2020		2021	
LINE NO.	CLASS OF CAPITAL	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		$		$		$		$	
1	SHORT-TERM DEBT	176,044,884	4.70%	58,545,810	1.42%	139,691,399	3.27%	198,246,243	4.45%
2	LONG-TERM DEBT	1,584,272,691	42.30%	1,885,497,029	45.59%	1,870,639,513	43.74%	1,895,706,225	42.55%
3	COMMON EQUITY	1,984,680,729	53.00%	2,191,813,909	53.00%	2,266,620,731	53.00%	2,360,970,399	53.00%
4	TOTAL CAPITAL	3,744,998,304	100.00%	4,135,856,748	100.00%	4,276,951,643	100.00%	4,454,922,868	100.00%

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(12)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

12. Rate base;

Response:

See attached.

KENTUCKY UTILITIES COMPANY

Net Original Cost Kentucky Jurisdictional Rate Base as of December 31,

		FORECASTED			
		2018	2019	2020	2021
	Title of Account (1)	Kentucky Jurisdictional Pro Forma Base Rate Base (2)	Kentucky Jurisdictional Pro Forma Base Rate Base (3)	Kentucky Jurisdictional Pro Forma Base Rate Base (4)	Kentucky Jurisdictional Pro Forma Base Rate Base (5)
1.	Utility Plant at Original Cost	$ 7,357,632,645	$ 7,906,912,346	$ 8,193,853,598	$ 8,549,176,970
2.	Deduct:				
3.	Reserve for Depreciation	2,833,816,109	2,996,093,238	3,159,196,674	3,366,290,810
4.	Net Utility Plant	4,523,816,537	4,910,819,108	5,034,656,924	5,182,886,160
5.	Deduct:				
6.	Customer Advances for Construction	951,647	951,647	951,647	951,647
7.	Accumulated Deferred Income Taxes	939,222,681	985,213,394	971,007,797	962,025,449
8.	Investment Tax Credit	79,747,726	83,848,703	82,074,961	80,301,219
9.	Total Deductions	1,019,922,053	1,070,013,744	1,054,034,404	1,043,278,315
10.	Net Plant Deductions	3,503,894,483	3,840,805,364	3,980,622,520	4,139,607,845
11.	Add:				
12.	Materials and Supplies	109,068,057	114,054,034	117,753,670	123,308,821
13.	Prepayments	15,330,016	15,191,698	15,747,454	15,511,184
14.	Emission Allowances	-	-	-	-
15.	Cash Working Capital	52,828,915	94,575,434	94,447,119	94,452,019
16.	Total Additions	177,226,988	223,821,165	227,948,244	233,272,025
17.	Total Net Original Cost Rate Base	$ 3,681,121,471	$ 4,064,626,529	$ 4,208,570,764	$ 4,372,879,870

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(13)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

13. Gallons of water projected to be sold (water);

Response:

Not applicable to KU's Application.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(14)
Sponsoring Witness: David S. Sinclair

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

14. Customer forecast (gas, water);

Response:

Not applicable to KU's Application.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(15)
Sponsoring Witness: David S. Sinclair

<u>Description of Filing Requirement:</u>

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

15. Sales volume forecasts – cubic feet (gas);

<u>Response:</u>

Not applicable to KU’s Application.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(16)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

16. Toll and access forecast of number of calls and number of minutes (telephone); and

Response:

Not applicable to KU's Application.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(17)
Sponsoring Witness: Robert M. Conroy

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

17. A detailed explanation of other information provided, if applicable.

Response:

Not applicable to KU’s Application.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(i)
Sponsoring Witness: Christopher M. Garrett

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission or Federal Communications Commission audit reports.

Response:

The most recent Federal Energy Regulatory Commission ("FERC") audit report relating to KU is attached. The Federal Communications Commission has not conducted an audit of KU, and, therefore, no such audit reports exist.

In Reply Refer To:
Office of Enforcement
Docket No. FA12-12-000
October 9, 2014

PPL Corporation
Attention: Robert J. Grey
Executive Vice President, General Counsel and Secretary
Two North Ninth St.
Allentown, PA 18101

Dear Mr. Grey:

1. The Division of Audits and Accounting within the Office of Enforcement (OE) has completed an audit of PPL Corporation (PPL), including its service companies and associated companies. The purpose of the audit was to evaluate the companies' compliance with Federal Energy Regulatory Commission (Commission): (1) cross-subsidization restrictions on affiliate transactions under 18 C.F.R. pt. 35; (2) accounting, recordkeeping, and reporting requirements under 18 C.F.R. pt. 366; (3) Uniform System of Accounts (USofA) for centralized service companies under 18 C.F.R. pt. 367; (4) preservation of records requirements for holding and service companies under 18 C.F.R. pt. 368; and (5) FERC Form No. 60 annual report requirements under 18 C.F.R. pt. 369.

The audit evaluated PPL's associated public utilities' compliance with Commission accounting requirements for transactions with associated companies under 18 C.F.R. pt. 101 and the applicable reporting requirements in the FERC Form No. 1. The audit also evaluated compliance with the conditions upon which the Commission granted merger and acquisition of jurisdictional facilities authorization in Docket No. EC10-77-000.

Moreover, the audit evaluated Kentucky Utilities Company (KU) and Louisville Gas and Electric Company's (LG&E) compliance with their transmission cost-of-service formula rate schedule included as Attachment O of KU and LG&E's Open Access Transmission Tariff (OATT) and PPL Electric Utilities Corporation's compliance with its transmission cost of service formula rate schedule included as Attachment H-8-G of PJM Interconnection, L.L.C.'s OATT. The audit covered the period from January 1, 2010 through December 31, 2011. The enclosed audit report explains our audit findings and recommendations.

2. On September 26, 2014, PPL agreed with the findings and accepted the recommendations contained in the audit report. PPL stated it has already undertaken some corrective actions, as observed in the audit report.

3. In addition, PPL also provided descriptions of the planned corrective actions it will take to comply with the audit report recommendations and provided target completion dates. The appendix to the audit report includes a copy of PPL's response. I hereby approve the audit report.

4. PPL should submit its implementation plan within 30 days of this letter and make quarterly submissions to DAA describing the progress made to comply with the recommendations. As indicated in the audit report, these submissions 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 corrective actions are completed.

5. The Commission delegated the authority to act on this matter to the Director of OE under 18 C.F.R. section 375.311 (2013). This letter order constitutes final agency action. PPL may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. section 385.713 (2013).

6. 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. In addition, any instance of non-compliance not addressed herein or that may occur in the future may also be subject to investigation and appropriate remedies.

7. I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Bryan K. Craig, Director and Chief Accountant, Division of Audits and Accounting at (202) 502-8741.

Sincerely,

Larry D. Gasteiger
Acting Director
Office of Enforcement

Enclosure

Federal Energy Regulatory Commission

Audit of
PPL Corporation's Affiliate Transactions, and Compliance with:

- Cross-subsidization Restrictions on Affiliated Transactions;

- Regulations under the Public Utility Holding Company Act of 2005;

- Uniform System of Accounts for Public Utilities and Accounting for Service Company Billings;

- Merger Conditions under Docket No. EC10-77-000; and

- Transmission Formula Rates

Docket No. FA12-12-000
October 9, 2014

Office of Enforcement
Division of Audits and Accounting

TABLE OF CONTENTS

I. Executive Summary

A. Overview

The Division of Audits and Accounting (DAA) within the Office of Enforcement has completed an audit of PPL Corporation (PPL), including its service and associated companies. The audit was commenced to evaluate compliance with the Federal Energy Regulatory Commission's (FERC or the Commission): (1) cross-subsidization restrictions on affiliate transactions;[1] (2) accounting, recordkeeping, and reporting requirements;[2] (3) Uniform System of Accounts (USofA) for centralized service companies;[3] (4) preservation of records requirements for holding and service companies;[4] and (5) FERC Form No. 60 annual report requirements.[5]

The audit evaluated PPL's associated public utilities' compliance with Commission accounting requirements for transactions with associated companies under 18 C.F.R. pt. 101 and applicable reporting requirements in the FERC Form No. 1. The audit also evaluated compliance with the conditions upon which the Commission granted merger and acquisition of jurisdictional facilities authorization in Docket No. EC10-77-000. Lastly, the audit evaluated Kentucky Utilities Company (KU) and Louisville Gas and Electric Company's (LG&E) compliance with their transmission cost-of-service formula rate schedule included as Attachment O of KU and LG&E's Open Access Transmission Tariff (OATT) and PPL Electric Utilities Corporation's (PPL Electric) compliance with its transmission cost-of-service formula rate schedule included as Attachment H-8-G of PJM Interconnection, L.L.C.'s (PJM) OATT. The audit covered the period from January 1, 2010 through December 31, 2011.

Based on audit staff examination of KU, LG&E, and PPL Electric's accounting and formula rate calculations, audit staff identified numerous areas of substantial non-compliance with various Commission requirements. The level of non-compliance and the seriousness of these matters uncovered during the audit resulted in excessive formula rate billings to wholesale transmission customers. Audit staff is very concerned that the lack of sufficient oversight of PPL's accounting and formula rate policies that impact rate recovery have contributed to erroneous and excessive formula rate billings to wholesale

[1] 18 C.F.R. pt. 35.

[2] *Id.* pt. 366.

[3] *Id.* pt. 367.

[4] *Id.* pt. 368.

[5] *Id.* pt. 369.

transmission customers. Audit staff is also concerned that wholesale transmission customers would have continued to pay excessive amounts through formula rate billings had these areas of non-compliance gone undetected by audit staff. However, audit staff is encouraged by PPL's: (1) cooperation throughout the entire audit process and (2) swift and comprehensive implementation plan to correct these serious breaches of compliance with Commission requirements during and after the audit fieldwork. These areas of non-compliance are reflected in the compliance findings summarized in section C below and in full in section IV.

B. Transmission Formula Rate

<u>KU and LG&E</u>

KU and LG&E operate their system as a single, integrated, and coordinated transmission system and provide transmission service under the terms of their shared joint OATT. KU and LG&E adopted a formula rate for transmission service under schedule 7 (covering long-term firm and short-term firm point-to-point transmission service), schedule 8 (covering non-firm point-to-point transmission service), and schedule 9 (covering network integration service). The formula rate also provides for recovery of their Independent Transmission Organization and Reliability Coordinator costs.

The formula rate is in Attachment O to KU and LG&E's OATT. KU and LG&E are not required to file an annual informational or compliance filing for their wholesale transmission cost-of-service formula rate. Rather, KU and LG&E post the formula rate on OASIS by May 1, effective June 1, each year. All amounts in the formula rate are based on actual amounts. There are no over/under-collections, refunds, additional billings, projections, or estimates in the formula rate.

The transmission formula rate calculation is prepared in an Excel spreadsheet that primarily uses FERC Form No. 1 data. Each input item is identified within the spreadsheet, KU and LG&E's FERC Form No. 1 data are entered in the input section of the spreadsheet, and they are combined to calculate the final combined OATT rates. Sources of the data used to prepare the transmission formula rate are the KU and LG&E FERC Form No. 1s for the calendar year. Specific pages and line numbers are in the data entry section of the formula spreadsheet to help identify correct data points. After initial data entry is completed, separate teams in the accounting and transmission groups review the formula inputs and results to ensure data accuracy. The Rates and Regulatory (Rates) group maintains the spreadsheet where the formula rate is calculated. The Rates group enters data from the FERC Form No. 1, which allows formula rates to be calculated in the spreadsheet.

PPL Electric

PPL Electric is a member of PJM. PJM directs the operation of PPL Electric's transmission facilities, and transmission service over these facilities is provided under the PJM OATT. PPL Electric's annual transmission revenue requirement (ATRR) and annual transmission rates are set forth in Attachment H-8G to PJM's OATT, and the formula rate implementation protocols (Protocols) for the ATRR and rates are set forth in Attachment H-8H to PJM's OATT. The Protocols describe the process in which PPL Electric will account for certain inputs, updates to the formula, annual review procedures, and formal challenge procedures.

PPL Electric's ATRR established point-to-point transmission rates to the PPL Group Zone and Network Integration Transmission Service (NITS) rates in the PPL Group Zone. PPL Electric's ATRR is based on actual costs for transmission service for the preceding calendar year and based on associated FERC Form No. 1 data. PPL Electric is allowed to include the cost of weighted, capital additions projected for the current year, as well as projected CWIP for its transmission incentive project, Susquehanna-Roseland. PPL Electric also has a true-up mechanism through which deviations from actual costs will be addressed.

The ATRR produced by PPL Electric's approved formula rate is the sum of return on rate base, operation and maintenance expense, administrative and general expense, depreciation expense, taxes other than income tax, and income taxes, less any applicable revenue credits. PPL Electric's formula rate components are based on FERC Form No. 1 data and/or supporting documentation for data not otherwise available in the FERC Form No. 1. PPL Electric's Regulatory Compliance group manages the formula rate filing process, while other groups such as Transmission Expansion, Office of General Counsel, and Taxes provide data and various exhibits supporting some components. PPL Electric's formula rate filing is submitted to the Commission as an informational filing, due annually on or before May 15 of each year.

C. Summary of Compliance Findings

Audit staff's compliance findings are summarized below. Details are in section IV of this report. Audit staff identified the following areas of noncompliance:

- PPL Electric improperly accounted for its investment in PPL Receivables Corporation under the consolidated method of accounting instead of using the equity method of accounting, as required by the Commission. As a result of using the consolidated method instead of the equity method of accounting, PPL Electric erroneously included certain amounts in its formula rate billings to wholesale transmission customers.

- PPL Electric improperly accounted for overpayments of its current year's estimated Federal and state income taxes in Account 165, Prepayments.

- PPL Electric improperly accounted for manufactured gas plant remediation expenses in Account 930.2, Miscellaneous General Expenses. These expenses should have been accounted for so that no amounts would be recovered from wholesale transmission customers since these costs were not associated with obligations related to wholesale transmission customers. As a result of the incorrect accounting, these expenses were improperly included in the formula rate computation.

- KU and LG&E neither sought nor received Commission approval to recover asset retirement obligation costs in their transmission formula rate.

- KU did not remove all amounts from its formula rate calculations associated with its Virginia distribution utility plant facilities, as required by the Commission.

- KU and LG&E improperly accounted for cost of removal on physical assets related to asset retirement obligations.

- PPL's three franchised public utilities (KU, LG&E, and PPL Electric) incorrectly included some transaction-related costs related to PPL's merger with E.ON U.S. in formula rate billings to wholesale power and transmission customers.

- KU's method of computing Allowance for Funds Used During Construction (AFUDC) on Construction Work In Progress (CWIP) was deficient by compounding AFUDC monthly instead of semi-annually, including unrealized losses in its common equity balance used to calculate AFUDC, and using an incorrect balance for the common equity component.

- KU and LG&E's formula rate Attachment O included multiple inaccurate line references.

- FERC Form No. 60 filings that PPL Services Corporation (PPL Services) and LG&E and KU Services Company (LKS) made contained several reporting errors relating to account misclassifications, supporting schedule discrepancies, and the reporting of convenience payments.

D. Summary of Recommendations

Audit staff's recommendations to remedy the findings are summarized below. Detailed recommendations are in section IV. To address the areas of noncompliance, audit staff recommends the following:

1. PPL Electric should provide notice of its material accounting changes to its wholesale transmission customers as required by section III.B of Attachment H-8H, Formula Rate Implementation Protocols, of its Open Access Transmission Tariff.

2. PPL Electric should implement procedures to ensure that it follows the equity method of accounting for all investments in subsidiaries and ensure no deviation between accounting practices and Commission accounting regulations.

3. PPL Electric should adopt controls that will ensure all costs related to PPL Receivables' operating activities are excluded from all components in PPL Electric's formula rate calculation.

4. PPL Electric should refund all costs incorrectly included in and recovered through the formula rate since its inception, with interest, calculated in accordance with the formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

5. PPL Electric should file a refund report with the Commission that reflects amounts refunded to PPL Electric's wholesale transmission customers.

6. PPL Electric should reclassify Federal and state income taxes recorded in Account 165, Prepayments, applicable to those years in which PPL Electric chose to receive a refund of those amounts to Account 146, Accounts Receivable from Associated Companies, or Account 143, Other Accounts Receivable, as appropriate.

7. PPL Electric should submit correcting entries to the Division of Audits and Accounting within 30 days of this report.

8. PPL Electric should revise procedures to ensure its income tax transactions recorded to Account 165 represent actual prepayments.

9. PPL Electric should revise procedures to appropriately determine its tax accrual amount.

10. PPL Electric should record the necessary correcting entries as of December 31 to reflect the proper accounting for Federal and state estimated tax overpayment.

11. For each year these amounts were included in the formula rate calculations, PPL Electric should refund all costs incorrectly included in and recovered through the formula rate, with interest, calculated pursuant to its formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

12. PPL Electric should file a refund report with the Commission that reflects amounts refunded to PPL Electric's wholesale transmission customers.

13. PPL Electric should amend its accounting policies to ensure manufactured gas plant remediation expenses are accounted for consistent with the Commission's accounting regulations.

14. PPL Electric should refrain from including manufactured gas plant remediation expenses in the formula rate determinations, since such costs were not incurred in providing service to wholesale transmission customers.

15. PPL Electric should determine the amount of manufactured gas plant remediation costs recovered through its formula rate.

16. For each year affected, PPL Electric should refund the manufactured gas plant remediation expense amounts improperly included and recovered through the formula rate, calculated pursuant to its formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

17. PPL Electric should file a refund report with the Commission that reflects amounts refunded to its wholesale transmission customers.

18. LG&E and KU should submit a filing with the Commission under FPA section 205 to address their recovery of asset retirement obligation costs.

19. LG&E and KU should calculate the rate impact of recovering these ARO costs in the formula rate, and provide these calculations to the Division of Audits and Accounting.

20. For each year affected since the inception of their stand-alone formula rate, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate due to recovering asset retirement obligation costs, calculated with interest under section 35.19a of the Commission's regulations.

21. LG&E and KU should calculate the rate impact of recovering these costs in their stand-alone formula rate, and provide these calculations to the Division of Audits and Accounting.

22. For each year these Virginia distribution utility costs were included in their stand alone formula rate calculation, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate, calculated with interest under section 35.19a of the Commission's regulations.

23. LG&E and KU should provide to the Division of Audits and Accounting correcting entries that show the reversal of amounts from Account 254.

24. For each year these amounts were included in their stand-alone formula rate, LG&E and KU should refund all costs, calculated with interest under section 35.19a of Commission regulations.

25. LG&E and KU should file a refund report with the Commission that reflects amounts refunded to their customers.

26. PPL Electric, LG&E, and KU should strengthen existing procedures so that no transaction-related costs flow through an FPU's formula rates.

27. PPL Electric, LG&E, and KU should calculate the rate impact of recovering transaction-related costs in their respective formula rates, and provide these calculations to the Division of Audits and Accounting.

28. PPL Electric, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate due to the incorrect allocation of transaction-related costs, calculated with interest in accordance to the Commission-approved formula rate protocols for PPL Electric and under section 35.19a of the Commission's regulations for LG&E and KU.

29. KU should revise and implement procedures going forward to ensure its AFUDC base and rate calculation is consistent with Electric Plant Instruction 3(17) and other applicable Commission requirements.

30. LG&E and KU should develop and implement controls to ensure accurate and complete line references.

31. LG&E and KU should submit a filing with the Commission under FPA section 205 to address the incorrect formula rate line references.

32. LKS and PPL Services should develop and implement procedures to ensure proper account classification, consistent reporting, and completion of all supporting schedules of the FERC Form No. 60. As part of these procedures, incorporate an annual review to ensure the FERC Form No. 60 filed with the Commission is complete and accurate.

33. LKS and PPL Services should refile 2010 FERC Form No. 60, correcting all reporting errors within 90 days after this report is issued.

E. Compliance and Implementation of Recommendations

Audit staff further recommends that PPL:

- Submit its plans for implementing audit staff's recommendations for audit staff's review. PPL should submit these plans to audit staff within 30 days after this final audit report is issued.

- Submit all correcting entries to the Division of Audits and Accounting within 30 days after this final audit report is issued, including all correcting entries affecting the books for its associated franchised public utilities.

- Submit quarterly reports to the Division of Audits and Accounting describing PPL's progress in completing each corrective action recommended in this final audit report. PPL should make quarterly filings no later than 30 days after the end of each calendar quarter, beginning with the first quarter after the final audit report in this docket is issued, and continuing until PPL completes all recommended corrective actions.

- Submit copies of any written policies and procedures developed in response to recommendations in the final audit report. These policies and procedures should be submitted for audit staff review in the first quarterly filing after PPL completes these products.

II. Background Information

A. Description of PPL Corporation System

Headquartered in Allentown, PA, PPL is a public utility holding company with public utility and nonutility subsidiaries in the United States. PPL controls or owns approximately 19,000 megawatts of generating capacity in the United States, sells energy in U.S. markets, and delivers electricity and natural gas to about 10 million customers in the United States. PPL also owns a regulated distribution company in the United Kingdom that serves 7.8 million customers in Wales, and southwest and central England. During the audit period, PPL was the parent of three Commission-jurisdictional franchised public utilities (FPUs): PPL Electric, LG&E, and KU.[6]

PPL Electric delivers electricity to 1.4 million customers in eastern and central Pennsylvania, and owns transmission facilities within PJM's balancing authority area. PPL Electric does not have captive wholesale or retail customers, but is the default supplier for retail customers within its service area. LG&E is a public utility that owns and operates electric generation, transmission, and distribution facilities, as well as natural gas distribution, transmission, and storage facilities, in Kentucky and Indiana. LG&E serves 397,000 electric customers. KU is a public utility that owns and operates electric generation, transmission, and distribution facilities in Kentucky, with limited operations in Tennessee and Virginia. KU serves 516,000 electric customers in Kentucky and 30,000 electric customers in Virginia.

PPL's two centralized service company subsidiaries (LKS and PPL Services) provide a variety of services to PPL, affiliated FPUs, and other affiliates.

LKS provides a variety of administrative, management, engineering, construction, environmental, and support services to affiliated entities, including KU and LG&E, at cost. LKS was formed as a Kentucky corporation on June 2, 2000 and commenced operations as a service company on January 1, 2001. Following the repeal of the Public Utility Holding Company Act (PUHCA) of 1935 and the enactment of PUHCA 2005, LKS transitioned, effective January 1, 2008, to the Commission's USofA for centralized service companies under part 367. LKS is a wholly owned subsidiary of LG&E and KU Energy LLC (LKE), which in turn is a wholly owned subsidiary of PPL. LKS became an indirect, wholly owned subsidiary of PPL when PPL acquired all of the limited liability company's interest of LKE from E.ON U.S. LLC (E.ON U.S.) on November 1, 2010.

[6] The term franchised public utility means a public utility with a franchised service obligation under state law.

PPL Services, a Delaware corporation, is a wholly owned subsidiary of PPL. PPL Services also provides various administrative services at cost to affiliated entities, including LKS and PPL Electric. PPL Services was formed as a corporate entity on February 14, 2000 as a PPL subsidiary. When PPL Services was formed, PPL was a single state exempt holding company under PUHCA 1935, so PPL Services was not subject to regulation as a centralized service company. PPL remained a single state exempt holding company after PUHCA 2005 was passed. On October 26, 2010, the Commission issued an order under section 203 of the Federal Power Act (FPA), authorizing PPL's acquisition of E.ON U.S. As a result of the acquisition of E.ON U.S., PPL derived more than 13 percent of its public utility company revenues from outside of a single state. After the acquisition, PPL notified the Commission that it no longer qualified for the waiver from applicable accounting, record retention, and reporting requirements under part 366 of the Commission's regulations as a single state holding company and notified the Commission it no longer sought to maintain its waiver as a single state holding company. Due to the acquisition of E.ON U.S. and PPL's change in status under PUHCA 2005, PPL Services fell under regulation as a centralized service company under PUHCA 2005 on November 1, 2010. The basic organizational structure of PPL Services has not changed significantly since it was formed in 2000.

B. Non-Power Goods and Services

LKS and PPL Services are the centralized service companies within PPL's holding company system that provide business support services to PPL, affiliated FPUs, and other subsidiaries. During the audit period, the service companies had service agreements between themselves and the FPUs. Under these agreements, the service companies provided administrative and professional services to PPL, its associated public utilities, and other PPL nonregulated operating companies "at-cost." Specifically, these administrative and professional services included, among others, corporate audit services, environmental management services, facilities management, financial accounting and reporting services, human resources, IT support, tax services, and legal services. Also, affiliated companies provided PPL's FPUs with other non-power goods and services. Such services were provided under agreements for mutual assistance, gas transportation services, insurance services, third-party services, data hosting, and intercompany billing support.

C. Service Company Accounting Systems

Cost accumulation and tracking at PPL Services is accomplished using two systems: PeopleSoft Project Costing (Project Costing) and PowerPlant. Project Costing is the system where projects are created and serves as the repository for amounts from various subsystems, such as payroll, accounts payable, and inventory. PPL Services tracks expenses by project. These can either be expense or capital projects. The Commission account for applicable costs is assigned as part of this Project Costing. PowerPlant contains plant records for PPL Services and serves as the database for its property records. PowerPlant data fields are updated by a nightly interface with PeopleSoft. Any capital projects established in PowerPlant are reviewed for proper accounting set up by the Asset Management group, which is part of the Controller's department. PowerPlant calculates depreciation expense as well as any capitalized interest. At month end, PowerPlant creates journal entries that are interfaced back to the PeopleSoft general ledger. PowerPlant is used exclusively for accumulating costs for capital projects.

Classification of accounts is maintained by the Corporate Accounting department in the Shared Accounting Services group and conforms to the requirements of the USofA. The classification also establishes accounting requirements as applicable to transactions occurring under normal circumstances in the ordinary course of business. The general ledger records and maintains activity and balances for direct and indirect costs. The general ledger also runs a monthly process to allocate indirect service company costs recorded, by category, from the service company to various PPL business lines as defined by the Financial Planning group. Also, the Financial Planning group created manual journal entries, and reviewed and approved direct cost allocations from the service company to the various business lines.

LKS cost accumulation and tracking is accomplished using Oracle products. Transactions affecting LKS post to the Oracle general ledger and originate from spreadsheet journal entries and mass allocations generated within the Oracle general ledger module, and from the subsidiary systems' Oracle Project Accounting, Oracle Payables, Oracle Purchasing, PowerPlant, the VOLTS timekeeping system, and the Transportation Resource Management System.

LKS uses the Oracle Project Accounting (Project Accounting) module to capture and accumulate direct and indirect costs. Projects have been created for each associated company, which receives charges with tasks designated to record income statement charges for direct and indirect labor, and for direct and indirect nonlabor. Charges from LKS to projects with tasks set up to balance sheet accounts on associated companies are designated as direct. Labor burdens are designated as indirect, consistent with the treatment on the FERC Form No. 1. LKS employees record their time through the timekeeping system to the appropriate direct or indirect labor tasks, and the labor is interfaced to Project Accounting and the general ledger. Nonlabor charges are recorded to appropriate direct or indirect nonlabor tasks via coding on purchase orders, disbursement requests, purchasing cards, or expense reports. After employees' labor charged to associated companies is interfaced from Project Accounting and posted to the general ledger, an Oracle process calculates burden components on this labor. This process debits direct burden accounts for all labor, including indirect labor. Another Oracle process then moves burden amounts from direct burden accounts to indirect burden accounts.

D. Cost Allocation Methods

The service companies directly and indirectly charge costs to affiliates. Directly charged costs are identifiable and charged entirely to the appropriate affiliate, while indirectly charged costs require application of different cost allocation methodologies to determine charges. These methodologies are based on several factors such as number of employees, number of transactions, number of customers, or occupied square footage. In general, the service companies charge costs to affiliates in one of three ways:

- Costs for services performed for an affiliate are directly charged to the affiliate.
- Costs for services performed for two or more affiliates are distributed among and charged to the affiliates, using methods determined on a cost-causation basis consistent with the type of work performed and based on an allocation method.
- Costs for general services, which are applicable to all affiliates or a class or classes of affiliates, are allocated among or charged to such affiliates by application of one or more cost allocation methods.

LKS reported approximately $296 million in service costs for 2011. Moreover, LKS directly charged some 47 percent and allocated 53 percent of costs to affiliates with respect to non-power goods and services it provided. KU and LG&E received about 88 percent of the service company's charges during 2011. LKS neither directly charged nor allocated any costs to PPL Electric during 2011. LKS directly charged or allocated costs to affiliates using 18 different allocation methods.

PPL Services reported approximately $400 million in service costs for 2011. Moreover, it directly charged some 59 percent and allocated 41 percent of costs to affiliates with respect to non-power goods and services it provided. PPL Electric received about 36 percent of the service company's charges during 2011. PPL Services neither directly charged nor allocated any costs to KU or LG&E during 2011. PPL Services directly charged or allocated costs to affiliates using 11 different allocation methods.

E. Internal Audit Role and Reporting

PPL's Internal Audit department is divided into three branches: PPL Audit Services, Special Projects, and LKE Audit Services. The executive director of the Internal Audit department reports functionally to the Audit Committee of the Board of Directors and reports administratively to the Chairman/President/CEO. Most of these staffers have Certified Public Accountant and/or Certified Internal Auditor professional certifications.

The Internal Audit department uses and complies with the Institute of Internal Auditors' International Standards for the Professional Practice of Internal Auditing. Each quarter, the Internal Audit department prepares a report for the PPL Audit Committee that addresses key risk areas assessed during the quarter, a summary of audit results, a summary of significant or material control deficiencies, audit performance measures, and a summary of select in-progress audits. Each year, the Internal Audit department also reports to the PPL Audit Committee on overall control environment, Sarbanes-Oxley section 404 compliance, audit organization and qualifications, budget and expenditures, annual audit plans, and the Internal Audit department's charter. The Internal Audit department did not perform any work that directly related to the scope areas in this audit.

F. Acquisition of E.ON U.S.

On November 1, 2010, PPL purchased E.ON U.S., the parent company of Kentucky's two major utilities, KU and LG&E, for $7.625 billion from German utility firm E.ON AG. On October 25, 2010, the Commission issued an order approving this acquisition of all issued and outstanding limited liability company interests of E.ON U.S.[7] As a result of the transaction, E.ON U.S. became a direct, wholly owned subsidiary of PPL, and E.ON U.S.'s subsidiaries, including KU and LG&E, became indirect, wholly owned subsidiaries of PPL. In its Merger Order approving the transaction, the Commission required that transmission and wholesale customers be held harmless from costs related to the transaction for five years to the extent that such costs would exceed savings related to the transaction.

[7] *PPL Corporation*, 133 FERC ¶ 61,083 (2010) (Merger Order).

III. Introduction

A. Objectives

The audit's objectives were to determine whether PPL and its associated companies complied with: (1) Commission cross-subsidization restrictions on affiliate transactions; (2) accounting, recordkeeping, and reporting requirements; (3) the USofA for centralized service companies; (4) Commission preservation of records requirements for holding companies and service companies; and (5) FERC Form No. 60 Annual Report requirements. The audit evaluated PPL's associated public utilities' compliance with Commission accounting requirements for transactions with associated companies and applicable reporting requirements in the FERC Form No. 1. The audit also evaluated compliance with the conditions upon which the Commission granted merger and acquisition of jurisdictional facilities authorizations in Docket No. EC10-77-000. Lastly, audit staff examined KU, LG&E, and PPL Electric's compliance with their transmission cost-of-service formula rate schedules within the respective OATTs. The audit covered January 1, 2010 through December 31, 2011.

B. Scope and Methodology

To address overall audit objectives, audit staff:

- Identified standards and criteria used to evaluate compliance with each audit scope area. They included Commission rules, regulations, letter orders, and other requirements for holding and service companies, and Commission accounting regulations for jurisdictional public utilities.

- Reviewed FERC-65, Notification of Holding Company Status, and FERC Form No. 60 Annual Reports to ensure filed information was reliable, accurate, and complete.

- Reviewed publicly available materials to understand PPL's operations, including select filings to the SEC (Forms 10-K and 10-Q), FERC Form Nos. 1 and 60 filings, prior audits, and other filings with the Commission.

- Conferred with officials from the Pennsylvania, Kentucky, Virginia, and Tennessee public utility commissions, which have jurisdiction over PPL's FPUs.

- Conducted site visits to corporate headquarters in Allentown, PA, and Louisville, KY. The visits enabled audit staff to understand PPL's structure, activities, functions, systems, and the processes used in its operations. While on site, audit staff reviewed and tested supporting details for PPL's allocation methods; interviewed PPL staff responsible for accounting, financial reporting, record retention, cost allocations, and PPL's compliance program; sampled select supporting documents to ensure the service companies' accounting complied with Commission accounting regulations; sampled select supporting documents to ensure that billings and associated public utilities' accounting for these billings complied with Commission accounting regulations; and tested compliance with preservation of records requirements.

- Conducted interviews, teleconferences, and met with PPL employees to discuss processes, procedures, operations, and observations.

- Discussed data responses with PPL employees, and clarified and supplemented data responses with more information on areas of specific concern.

- Reviewed relevant audit reports and working papers of the Internal Audit department and external audit firm Ernst & Young LLP.

- Conferred with other Commission staff on various compliance issues to ensure audit findings would be consistent with Commission precedent and policy. For example, audit staff spoke with staff from other divisions within the Office of Enforcement, and with technical and legal staff from other Commission offices, including the Office of Energy Market Regulation and the Office of General Counsel.

Audit staff performed several specific actions to evaluate compliance with all relevant requirements relating to audit objectives. A summary of these actions includes:

Cross-subsidization Restrictions

To evaluate compliance with Commission cross-subsidization restrictions on affiliate transactions, audit staff:

- Reviewed policies, procedures, and practices related to the sale of non-power goods and services.

- Interviewed PPL employees, particularly those who account and report transfers of non-power goods and services.

- Reviewed and tested pricing mechanisms for non-power goods and services the FPUs provided to and received from each other, service companies, and other nonutility affiliates.

- Sampled charges and payments to determine accurate pricing for the sale of goods and services.

Accounting, Recordkeeping, and Financial Reporting

To evaluate compliance with Commission accounting, recordkeeping, and financial reporting regulations, audit staff:

- Reviewed FERC Form No. 60 Annual Report filings, Notification of Holding Company Status – FERC-65 filings, and the public utilities' FERC Form No. 1 reports. Audit staff also verified select, electronically filed information reported on the FERC Form No. 60 filings with supporting books and records to ensure reported information was accurate and complete.

- Compared select information in the FERC Form No. 1s with the FERC Form No. 60s to ensure information was reported accurately and consistently. Also, audit staff reviewed page 429 of the FERC Form No. 1s, which included non-power goods and services transactions for each FPU.

- Reviewed, sampled, analyzed, and tested select centralized service company accounting data.

- Sampled FPUs' accounting for select costs received from the centralized service companies.

Cost Allocation and Billings

To evaluate service company cost allocation methodologies and billings, audit staff:

- Identified cost allocation methods used, and identified and reviewed new allocation methods to facilitate our review of the service companies' cost allocation methods and costs the service companies billed to PPL's FPUs. Also, audit staff reviewed and tested billings and supporting details behind select allocation methods.

Preservation of Records

To evaluate compliance with Commission preservation of records requirements, audit staff:

- Interviewed PPL employees responsible for retaining records for the service companies.

- Requested and tested select records to ensure their retention.

Merger and Acquisition Authorizations Compliance Review

To evaluate compliance with conditions of the Commission's Merger Order, audit staff:

- Reviewed PPL's applications and related Commission filings and orders to understand the terms, conditions, and context of the merger and acquisition request, and identify commitments made in applicable orders.

- Examined procedures and controls for compliance with "hold harmless" provisions the Commission established in its merger and acquisition order. This included a review of accounting filings for recovery of transaction-related costs, controls for compliance oversight, and rates to ensure cost recoveries were appropriate.

- Discussed the merger with state public utility commissions that regulate PPL to understand their merger oversight and any concerns related to the post-merger company.

- Evaluated PPL's implementation process to ensure compliance with the merger's hold harmless provisions, requiring PPL to hold wholesale power and transmission customers harmless for five years from merger costs that may exceed merger-related savings.

- Interviewed employees involved in merger costs and synergy savings tracking.

- Tested certain amounts recorded as merger costs and synergy savings to determine appropriate classification and the level of support maintained.

Transmission Formula Rate

To evaluate each FPU's compliance with its respective formula rates, audit staff:

- Evaluated PPL Electric's compliance with its transmission cost-of-service formula rate in Attachment H-8G and the related Protocols set forth in Attachment H-8H to PJM's OATT, and KU and LG&E's compliance with their transmission cost-of-service formula rate in Attachment O to their joint OATT, including filings containing inputs to the formula rate.

- Reviewed initial and all subsequent Commission orders accepting the formula rate, including orders approving related settlements and PPL filings. Determined the level of functionalization, derivation of allocation factors, return on equity, rate base, accumulated depreciation, and other expenses. Reviewed background information about specific cost treatment, deferrals, cost caps, disallowances, and other matters disclosed as part of approving the derivation of the formula rate.

- Evaluated processes, procedures, and controls used to prepare and review the formula rate and annual updates, true-ups, or informational filings associated with the formula rate.

- Reviewed formula rate mechanics (forward-looking, historical, true-up, and informational filings), including a comprehensive overview of the formula rate mechanism the company provided.

- Evaluated the FERC Form No. 1 reporting processes and procedures to ensure accurate and complete reporting. As part of this evaluation, audit staff reconciled FERC Form No. 1 data with formula rate calculations and reviewed all discrepancies.

- Reviewed the FERC Form Nos. 1 and 3-Q, including related notes to financial statements to identify major accounting matters. Audit staff highlighted significant notes to understand financial statement and formula rate implications, and identified underlying accounting entries for these significant accounting matters.

- Determined whether the FPUs' accounting for significant matters impacted the formula rate calculation.

- Evaluated whether PPL's FPUs applied formula rate inputs in compliance with rate approval orders.

- Reconciled formula rate inputs derived from the FERC Form No. 1 to FPU books and records. Evaluated compliance with the USofA for the inputs under review, including all related guidance and accounting releases and accounting treatment of input items.

- Evaluated various accounts incorporated into cost-of-service formula rates and compliance with relevant accounting regulations in the UsofA.

Besides these actions, audit staff reviewed PPL's regulatory compliance program. Audit staff assessed the program for audit scope areas consistent with prior Commission orders and policy statements. Specifically, audit staff:

- Reviewed PPL's regulatory compliance program structure, including its authority and responsibilities for overseeing corporate compliance and the delegation of compliance responsibilities.

- Reviewed the Internal Audit department structure, including its chain-of-command and access to the Board of Directors through its Audit Committee to assess the effectiveness and independence of the audit function.

- Interviewed PPL executives, managers, and operational employees to evaluate their knowledge and application of the compliance program.

IV. Findings and Recommendations

1. Long-Term Investment in Subsidiary

PPL Electric improperly accounted for its investment in PPL Receivables under the consolidated method of accounting instead of using the equity method of accounting, as required by the Commission. As a result of using the consolidated method instead of the equity method of accounting, PPL Electric erroneously included certain amounts in its formula rate billings to wholesale transmission customers.

Pertinent Guidance

On February 1, 1973, the Commission issued Order No. 469 to amend the requirements of the Uniform System of Accounts to adopt the equity method of accounting for long-term investments in subsidiaries.[8]

18 C.F.R. pt. 101, Account 123.1, Investment in Subsidiary Companies, states:

> A. This account shall include the cost of investments in securities issued or assumed by subsidiary companies and investment advances to such companies, including interest accrued thereon when such interest is not subject to current settlement plus the equity in undistributed earnings or losses of such subsidiary companies since acquisition. This account shall be credited with any dividends declared by such subsidiaries.

18 C.F.R. pt. 101, Account 418.1, Equity in Earnings of Subsidiary Companies, states:

> This account shall include the utility's equity in the earnings or losses of subsidiary companies for the year.

Instructions to the schedule on page 224 of the FERC Form No. 1, Investments in Subsidiary Companies (Account 123.1), require in part:

> 1. Report below investments in Accounts 123.1, Investments in Subsidiary Companies.

[8] *Revisions in the Uniform System of Accounts, and Annual Report Forms No. 1 and No. 2 to Adopt the Equity Method of Accounting for Long-Term Investments in Subsidiaries*, Order No. 469, 49 FPC 326 (1973), *rehearing denied*, 49 FPC 1028 (1973).

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.

PJM Interconnection L.L.C., FERC Electric Tariff, Attachment H-8H, sections I, III.B states, in part:

> I.H "Material Accounting Change" means any (i) change in PPL Electric's accounting policies and practices, or (ii) change in PPL Electric's inter-corporate cost allocation policies or practices from those policies and/or practices in effect for the Rate Year upon which the immediately preceding Annual Update was based, which change causes a result under the Formula Rate difference than the result under the Formula Rate as calculated without such change.
>
> III.B. (2) The Annual Transmission Revenue Requirement shall be based on PPL Electric's books and records which reflect data properly recorded in: PPL Electric's FERC Form No. 1 to the extent the Formula Rate specifies the FERC Form No. 1 data as the input source; and The Commission's Uniform System of Accounts, as each exists as of the last day of the preceding calendar year.
>
> III.B. (3)(b) The Annual Update shall provide notice of Material Accounting Changes, which may incorporate by reference applicable disclosure statements filed with the SEC.

Background

Since 1973, the Commission has adopted the equity method of accounting for long-term investments in subsidiaries. Under the equity method of accounting, the investment in subsidiaries is recorded in Account 123.1, Investment in Subsidiary Companies (Major Only).[9] This account is increased or decreased based on a utility's proportionate share of subsidiary earnings regardless of whether such earnings were paid out as dividends to that utility. Although the Commission adopted the equity method of accounting for long-term investment in subsidiaries, it maintained its policy for ratemaking purposes that undistributed earnings of the subsidiary are to be excluded from the equity portion of the jurisdictional company capital structure in determining the rate of return.

[9] *Id*.

PPL Electric has three investments in the following subsidiary companies: CEP Commerce, LLC (CEP Commerce), CEP Lending, Inc. (CEP Lending), and PPL Receivables Corporation (PPL Receivables). PPL Electric has full control of these entities through 100 percent ownership of direct voting rights. CEP Commerce is the parent of CEP Lending, a company formed to make intercompany loans to all of PPL affiliates. PPL informed audit staff that PPL Receivables was formed to serve only the financing needs of PPL Electric. PPL Receivables is a special purpose entity whose sole purpose is to buy eligible accounts receivable and unbilled revenue from PPL Electric to secure asset-backed commercial paper from a third party.

Audit staff examined PPL Electric's accounting for its long-term investment in subsidiaries and found that it used the equity method of accounting to account for its long-term investment in CEP Commerce and CEP Lending. Conversely, it used the consolidated method of accounting to account for its long-term investment in PPL Receivables since its inception in 2004.

PPL Electric used various income statement and balance sheet accounts to record its long-term investment in PPL Receivables under the consolidated method of accounting. During the course of the audit fieldwork, PPL Electric filed its 2012 FERC Form No. 1 as required by Commission regulations.[10] On page 450.1 of the refiled 2012 FERC Form No. 1, PPL Electric disclosed the accounting impact if it had followed the Commission's approved method of accounting for subsidiary investments, which was the equity method of accounting. In addition, audit staff noted that some of these accounts and associated amounts flowed through the formula rate billings to transmission customers.

Audit staff determined that PPL Electric appropriately accounted for its long-term investment in CEP Commerce and CEP Lending using the equity method of accounting. However, PPL Electric did not properly account for its long-term investment in PPL Receivables based on the equity method of accounting, as required by Commission accounting regulations. The Commission's accounting regulations require that long-term investments in subsidiaries be recorded in Accounts 123.1 and 418.1, Equity in Earnings of Subsidiary Companies. Also, PPL Electric should not have included certain amounts in formula rate billings to wholesale transmission customers associated with using the consolidated method of accounting for PPL Receivables. Lastly, audit staff did not find sufficient evidence demonstrating that PPL Electric provided notification to its customers that it was using an accounting method not prescribed by the Commission to account for its long-term investment in PPL Receivables using the consolidated versus the equity method of accounting.

[10] 18 C.F.R. section 141.1.

Since PPL Electric neither sought nor received retroactive relief to use the consolidated method of accounting for its subsidiary investment in PPL Receivables, it must refund amounts erroneously included in formula rate billings to transmission customers since 2004.

Recommendations

We recommend that:

1. PPL Electric should provide notice of its material accounting changes to its wholesale transmission customers as required by section III.B of Attachment H-8H, Formula Rate Implementation Protocols, of its Open Access Transmission Tariff.

2. PPL Electric should implement procedures to ensure that it follows the equity method of accounting for all investments in subsidiaries and ensure no deviation between accounting practices and Commission accounting regulations.

3. PPL Electric should adopt controls that will ensure all costs related to PPL Receivables' operating activities are excluded from all components in PPL Electric's formula rate calculation.

4. PPL Electric should refund all costs incorrectly included in and recovered through the formula rate since its inception, with interest, calculated in accordance with the formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

5. PPL Electric should file a refund report with the Commission that reflects amounts refunded to PPL Electric's wholesale transmission customers.

2. Tax Overpayments

PPL Electric improperly accounted for overpayments of its 2010 and 2011 estimated Federal and state income tax liability in Account 165, Prepayments.

Pertinent Guidance

18 C.F.R. pt. 101, Account 236(A) (B), Taxes Accrued, states:

A. This account shall be credited with the amount of taxes accrued during the accounting period, corresponding debits being made to the appropriate accounts for tax charges. Such credits may be based upon estimates, but from time to time during the year as the facts become known, the amount of the periodic credits shall be adjusted so as to include as nearly as can be determined in each year the taxes applicable thereto. Any amount representing a prepayment of taxes applicable to the period subsequent to the date of the balance sheet, shall be shown under account 165, Prepayments.

B. If accruals for taxes are found to be insufficient or excessive, correction therefore shall be made through current tax accruals.

Background

Audit staff reviewed PPL Electric's taxes and related procedures to understand why PPL Electric characterized taxes as prepaid. Specifically, audit staff asked PPL Electric to explain: (1) the calculation of its estimated Federal and state income tax liability each year; (2) the procedures for determining its estimated and actual Federal and state income tax liability; and (3) the documentation supporting its estimated and actual Federal and state income tax liability and Federal and state income tax prepayment determinations for 2010 and 2011.

PPL Electric determined its estimated Federal and state income tax liability each month by applying the applicable Federal and state income tax rates to its estimated taxable income. When quarterly income tax payments exceeded the estimated income tax liability, PPL Electric considered the income tax overpayment as a prepayment and then recorded this amount in Account 165. PPL Electric paid estimated Federal and state income taxes in four quarterly installments based on its estimated annualized taxable income.

Based on the examination of tax information, audit staff found that PPL Electric recorded Federal and state income tax overpayment amounts in Account 165 that were refunded to PPL Electric for tax years ending 2010 and 2011. Specifically, PPL Electric received refunds amounting to $59,843,908 and $17,272,745 for tax years 2010 and 2011, respectively. Thus, PPL Electric did not reduce any future year's tax liability by the 2010 and 2011 income tax overpayments.

While Account 165 of the Commission's accounting regulations allows the prepayment of income taxes to be recorded therein, Account 236 requires that such prepayments must be applicable to periods subsequent to the date of the balance sheet. Further, the Commission has defined prepayments included in Account 165 as expenses for a service or a supply paid in advance that will be consumed or used in future accounting periods, such as rent and insurance.[11] Audit staff believes PPL Electric's treatment of income tax overpayments as a prepayment is not consistent with the requirements of Account 165 or other Commission requirements because these monies were refunded and not used to pay PPL Electric's income tax obligations in advance.

PPL Electric included the income tax overpayments recorded in Account 165 in its formula rate as a component of rate base. Under the PJM OATT, PPL Electric is allowed to include prepaid amounts recorded to Account 165, Prepayments, as an item in the derivation of its rate base calculated in its formula rates. Prepayments, which represent amounts paid in advance for a good or service, are included as an adjustment to rate base and serve as an added benefit to transmission owners for costs essential to their operations but are prepaid, like insurance premiums. PPL Electric's prepayment input was the product of its applicable prepayment balance and its wages and salaries allocation factor. In conformance with notes to PPL Electric's formula rate, it can only include prepayments for its electric operations.

Because PPL Electric elected not to apply the income tax overpayments to future tax obligations, it should not have been reclassifying excess tax payments in Account 236 to Account 165. Audit staff is aware that PPL Electric engaged in this accounting practice during and prior to the audit period. Also, PPL Electric should not have recovered amounts for its overpayment of income taxes through its formula rate. For amounts determined to be potential refunds and not used to pay PPL Electric's tax obligations in advance, PPL Electric should reclassify state income tax prepayments to Account 143, Other Accounts Receivable, and Federal income tax prepayments to Account 146, Accounts Receivable from Associated Companies.

[11] *Entergy Services, Inc.*, Opinion No. 505, 130 FERC ¶ 61,023, at P 190 (2010).

Recommendations

We recommend that:

6. PPL Electric should reclassify Federal and state income taxes recorded in Account 165, Prepayments, applicable to those years in which PPL Electric chose to receive a refund of those amounts to Account146, Accounts Receivable from Associated Companies or Account 143, Other Accounts Receivable, as appropriate.

7. PPL Electric should submit correcting entries to the Division of Audits and Accounting within 30 days of this report.

8. PPL Electric should revise procedures to ensure its income tax transactions recorded to Account 165 represent actual prepayments.

9. PPL Electric should revise procedures to appropriately determine its tax accrual amount.

10. PPL Electric should record the necessary correcting entries as of December 31 to reflect the proper accounting for Federal and state estimated tax overpayment.

11. For each year these amounts were included in the formula rate calculations, PPL Electric should refund all costs incorrectly included in and recovered through the formula rate, with interest, calculated pursuant to its formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

12. PPL Electric should file a refund report with the Commission that reflects amounts refunded to PPL Electric's wholesale transmission customers.

3. Manufactured Gas Plant Obligations

PPL Electric improperly accounted for manufactured gas plant remediation expenses in Account 930.2, Miscellaneous General Expenses. As a result of the incorrect accounting, these expenses were improperly included in the formula rate computation. These expenses should have been treated such that no amounts would be recovered from wholesale transmission customers since these costs were not associated with providing service to wholesale transmission customers.

Pertinent Guidance

18 C.F.R. pt. 101, Account 242, Miscellaneous Current and Accrued Liabilities, states:

> This account shall include the amount of all other current and accrued liabilities not provided for elsewhere appropriately designated and supported so as to show the nature of each liability.

18 C.F.R. pt. 101, Account 253, Other Deferred Credits, states:

> This account shall include advance billings and receipts and other deferred credit items, not provided for elsewhere, including amounts which cannot be entirely cleared or disposed of until additional information has been received.

18 C.F.R. pt. 101, Account 426.5, Other Deductions, states:

> This account shall include other miscellaneous expenses which are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

18 C.F.R. pt. 101, Account 930.2, Miscellaneous General Expense, states:

> This account shall include the cost of labor and expenses incurred in connection with the general management of the utility not provided for elsewhere.

Background

PPL Electric incurred manufactured gas plant (MGP) environmental obligations to clean up contaminated sites in conjunction with the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. This act imposed joint and several liability for cleaning up contamination caused by hazardous substances. PPL Electric estimated its liability for MGP environmental remediation to be $3,874,758 and $696,010 in 2010 and 2011, respectively. PPL Electric accounted for the MGP environmental remediation contingencies by debiting Account 930.2, and crediting Account 242 or Account 253, as appropriate.

PPL Electric represented that it included the environmental remediation obligations related to the MGPs in Account 930.2 because the environmental costs could not be identified with a specific business line. Consistent with PPL Electric's accounting policy, when a specific business line cannot be identified, either due to contamination that related to the purchase of property or related to former operation of facilities no longer in service, the costs are recorded in Account 930.2.

Audit staff believes that PPL Electric's accounting for its MGP environmental obligations was not consistent with the Commission's accounting regulations because such obligations should not have been included in Accounts 930.2. Audit staff also noted that these costs were not related to providing service to wholesale transmission customers. Therefore, under the Commission's accounting regulations, PPL Electric should have accounted for the MGP environmental obligations by debiting the appropriate nonutility expense account, not a transmission or administrative and general expense account tied to the transmission formula rate, and crediting Account 242 or Account 253, as appropriate.

For ratemaking purposes, PPL Electric included amounts in Account 930.2 in formula rate determinations. The formula rate template permits PPL Electric to recover costs recorded in this account through the application of the transmission wages and salaries allocator. The transmission wages and salaries allocator is the ratio of transmission wages expense to total wages expense less administrative and general wages expense. The application of this allocation factor allowed PPL Electric to recover transmission-related costs recorded in Account 930.2.

As part of the examination of Account 930.2, audit staff determined that in 2010 and 2011 PPL Electric recorded $3,874,758 and $696,010, respectively, of MGP environmental remediation costs in this account and subsequently included these amounts in formula rate determinations. In addition, audit staff noted that PPL Electric recorded these MGP environmental obligations in Account 930.2 for years prior to the audit period. PPL Electric represented to audit staff that these amounts were related to its former MGPs, which include Brodhead Creek, Columbia Gas Plant, Milton Gas Plant, Mt. Joy Gas Plant, and Shamokin Gas Plant. These MGPs were owned by Pennsylvania Power and Light Company, to which PPL Electric is the successor. However, these MGPs are no longer reflected on PPL Electric's books. The MGPs were not used in PPL Electric's wholesale transmission operations. Rather, they were historically used to produce a low Btu gas that was distributed to the Pennsylvania Power and Light Company's retail gas utility customers during the earlier years of the company's operations, when it was both a natural gas and electric utility.

PPL Electric should amend its accounting policy for MGP environmental obligations to record such contingencies by debiting the appropriate nonoperating expense account and crediting Account 242 or Account 253, as appropriate. PPL Electric should also refrain from including these costs in formula rate determinations, since these costs were not associated with providing service to wholesale transmission customers.

Recommendations

We recommend that:

13. PPL Electric should amend its accounting policies to ensure manufactured gas plant remediation expenses are accounted for consistent with the Commission's accounting regulations.

14. PPL Electric should refrain from including manufactured gas plant remediation expenses in the formula rate determinations, since such costs were not incurred in providing service to wholesale transmission customers.

15. PPL Electric should determine the amount of manufactured gas plant remediation expenses recovered through its formula rate.

16. For each year affected, PPL Electric should refund the manufactured gas plant remediation expense amounts improperly included and recovered through the formula rate, calculated pursuant to its formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

17. PPL Electric should file a refund report with the Commission that reflects amounts refunded to its wholesale transmission customers.

4. Asset Retirement Obligation

KU and LG&E neither sought nor received Commission approval to recover asset retirement obligation costs in their transmission formula rate.

Pertinent Guidance

Order No. 631 states:

> However, public utilities, licensees, and natural gas companies with formula rate tariffs must not include any cost components related to asset retirement obligations in their formula rate billing tariffs for automatic recovery in their billing determinations without obtaining Commission approval. [12]

Order No. 631 goes on to say:

> The Commission finds that the issue of whether, and to what extent, a particular asset retirement cost must be recovered through jurisdictional rates should be addressed on a case-by-case basis in the individual rate change filed by public utilities, licensees, and natural gas companies. To ensure that all rate base amounts related to asset retirement obligations can be identified and excluded from the rate base calculation in a rate change filing, the Commission adds sections 35.18 and 154.315 to its rate change filing requirements. These new regulations require that public utilities, licensees, and natural gas companies who have recorded an asset retirement obligation on their books in accordance with this rule must, as part of any initial rate filing or general rate change filing, provide a schedule identifying all cost components related to the asset retirement obligation that are included in the book balances of all accounts reflected in the cost of service computation supporting the proposed rates. In addition, the regulations require that all asset retirement obligations related rate base items be removed from the rate base computation through an adjustment. If the public utility, licensee, or natural gas company is seeking recovery of an asset retirement obligation in rates, it must also provide a detailed study supporting the amounts proposed to be collected in rates. If the public utility, licensee, or natural gas company is not seeking

[12] *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, Order No. 631, 103 FERC ¶ 61,021, at P 60 (2003).

> recovery of the asset retirement obligation in rates, then it must remove all asset retirement obligation related cost components from its cost of service.[13]

Section 35.18 of the Commission's regulations specifically states:

> (a) A public utility that files a rate schedule, tariff or service agreement under section 35.12 or section 35.13 and has recorded an asset retirement obligation on its books must provide a schedule, as part of the supporting work papers, identifying all cost components related to the asset retirement obligations that are included in the book balances of all accounts reflected in the cost of service computation supporting the proposed rates. However, all cost components related to asset retirement obligations that would impact the calculation of rate base, such as electric plant and related accumulated depreciation and accumulated deferred income taxes, may not be reflected in rates and must be removed from the rate base calculation through a single adjustment.
>
> (b) A public utility seeking to recover nonrate base costs related to asset retirement costs in rates must provide, with its filing under section 35.12 or section 35.13, a detailed study supporting the amounts proposed to be collected in rates.
>
> (c) A public utility that has recorded asset retirement obligations on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.[14]

18 C.F.R. pt. 101, Account 182.3, Other Regulatory Assets, states, in part:

> When specific identification of the particular source of a regulatory asset cannot be made, such as in plant phase-ins, rate moderation plans, or rate levelization plans, account 407.4, Regulatory credits, shall be credited.

[13] *Id.* P 62.

[14] 18 C.F.R. section 35.18 (2012).

Background

KU and LG&E recorded 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 a separate 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.

General Instruction 25 of part 101 of the USofA defines an asset retirement obligation (ARO) as:

> A liability for the legal obligation associated with the retirement of a tangible long-lived asset that a company is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel.[15]

KU and LG&E initially recorded the ARO by debiting Account 101, Electric Plant in Service, and crediting Account 230, Asset Retirement Obligation. These AROs were for obligations associated with ash ponds, chemical storage, asbestos, coal storage, environmental ponds, and other operational matters.

To record the depreciation on the ARO assets, KU and LG&E debited Account 403.1, Depreciation Expense for Asset Retirement Costs, and credited Account 108, Accumulated Provision for Depreciation of Electric Utility Plant. This depreciation is calculated on a straight line basis over a life dictated by the settlement date of the ARO liability.

For accretion expense, KU and LG&E debited Account 411.10, Accretion Expense, and credited Account 230. The accretion expense recognizes the increase in the cost of removing an asset over its useful life.

Lastly, to defer the total depreciation on ARO costs and accretion on ARO liabilities, KU and LG&E debited Account 182.3, Other Regulatory Assets, and credited Account 407.4, Regulatory Credits. Account instructions to Account 182.3 would require KU and LG&E to credit Account 407.4, Regulatory Credits, when "specific identification of the particular source of a regulatory asset cannot be made." However, in this case, the particular source of the regulatory asset can be specifically identified as the depreciation initially recorded in Account 403.1 and the accretion initially recorded in Account 411.10. Therefore, KU and LG&E should have credited Accounts 403.1 and

[15] 18 C.F.R. pt. 101, General Instruction 25.

411.10 rather than Account 407.4. Audit staff understands that amounts deferred in Account 182.3 may have been included in depreciation expense recorded in Account 403.1 and previously collected from wholesale power and transmission customers. Due to these being previously collected, KU and LG&E overstated the regulatory asset recorded in Account 182.3. However, audit staff will not require KU and LG&E to reduce the regulatory asset to the extent KU and LG&E make refunds for the amounts previously collected.

Although KU and LG&E recorded the ARO assets and liability in Accounts 101 and 230, respectively, it included in rate base only the amounts recorded in Account 101 resulting in an increase in rate base. By not decreasing rate base by the amount recorded in Account 230, KU and LG&E overstated amounts included in rate base. Also, KU and LG&E flowed through the effects of the depreciation of the ARO assets recorded in Accounts 403.1 and 108 in the formula rate.

It is audit staff's understanding that ARO costs were included in LG&E and KU's formula rate calculation since inception of the formula rate. Based on Commission requirements, audit staff believes no aspect of the ARO should have been included in formula rate billings to wholesale power and transmission customers, absent KU and LG&E seeking approval from the Commission to include ARO amounts in formula rate determinations. This would have afforded the Commission the opportunity to request further information regarding KU and LG&E's accounting and the impacts of including ARO amounts to determine the annual revenue requirement. KU and LG&E should refund amounts previously collected from wholesale power and transmission customers related to their ARO obligations.

Recommendation

We recommend that:

18. LG&E and KU should submit a filing with the Commission under FPA section 205 to address their recovery of asset retirement obligation costs.

19. LG&E and KU should calculate the rate impact of recovering these ARO costs in the formula rate, and provide these calculations to the Division of Audits and Accounting.

20. For each year affected since the inception of their stand-alone formula rate, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate due to recovering asset retirement obligation costs, calculated with interest under section 35.19a of the Commission's regulations.

5. Virginia Distribution Utility Plant Costs

KU did not remove all amounts from its formula rate calculations associated with its Virginia distribution utility plant facilities, as required by the Commission.

Pertinent Guidance

The March 17, 2006 Commission order accepting KU and LG&E's attachment O formula rate stated:

> We accept the attachment O rate formula for use in Applicants' stand-alone OATT, subject to revision. We agree with Applicants that the proposed rate formula represents an appropriate rate methodology for inclusion in Applicants' stand-alone OATT. However, Applicants must exclude the cost of certain facilities in Virginia that the Commission has found to serve a distribution function and not a transmission function. [16]

Note M of Attachment O requires KU to remove transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until FERC Form No. 1 balances are adjusted to reflect application of seven-factor test).[17]

[16] *Louisville Gas and Electric Company, et al.*, 114 FERC ¶ 61,282 at P198, (2006) (Citing *Louisville Gas & Electric Co.*, 109 FERC ¶ 61,330 at P 8-9 (2004) (order affirming Presiding Judge's finding that certain facilities in Virginia that perform a distribution function must be excluded from the formula rates used in an interconnection agreement and transmission service agreement between Applicants and East Kentucky Coop.), *order denying reh'g*, 111 FERC ¶ 61,323 at P 50 (2005)).

[17] FERC uses a seven-factor test to determine whether an electric facility is distribution or transmission. FERC will give deference to state commission determinations, but that is limited by the expectation that the state follows the seven-factor test: (1) Local distribution facilities are normally in close proximity to retail customers; (2) local distribution facilities are primarily radial in character; (3) power flows into local distribution systems; it rarely, if ever, flows out; (4) when power enters a local distribution system, it is not reconsigned or transported onto some other market; (5) power entering a local distribution system is consumed in a comparatively restricted geographic area; (6) meters are based at the transmission/local distribution interface to measure flows into the local distribution system; and (7) local distribution systems will be of reduced voltage. Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,771, 31,981 (1996).

Background

KU's transmission facilities in southwestern Virginia consist of 22 miles of 500-kV lines, 44 miles of 161-kV lines, 8 miles of 138-kV lines, 114 miles of 69-kV lines, and 5 transmission substations.

In a March 2004 initial decision, an administrative law judge determined that these Virginia transmission facilities serve a distribution function and not a transmission function, and, therefore, KU must eliminate the cost of these facilities from the transmission rates it charges.[18] In December 2004, the Commission affirmed the administrative law judge's finding that these Virginia transmission facilities serve a distribution function and not a transmission function and stated that the costs of these facilities must be eliminated from the rates charged.[19] In the March 2006 order that conditionally approved KU's withdrawal from Midwest Independent Transmission System Operator, Inc. (MISO), the Commission again required KU to "exclude the cost of certain facilities in Virginia that the Commission has found to serve a distribution function and not a transmission function."[20]

During a review of the transmission formula rate calculation, audit staff determined that KU did not comply with Note M of Attachment O, which requires KU to remove transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test. KU acknowledged that its Virginia transmission facilities were state-jurisdictional, and KU should have removed the Gross Plant in Service cost of its Virginia transmission facilities and associated depreciation in the calculation of the Transmission Plant Allocator of Attachment O, in conformity with Note M of Attachment O.

Audit staff determined that, by not complying with Note M, KU did not remove certain expenses related to these Virginia distribution plant facilities from formula rate determinations. This includes not only amounts included in the calculation of rate base, return, depreciation, and income taxes that are allocated directly using the transmission plant allocator, but also amounts or expenses, such as accumulated deferred income taxes, operation and maintenance expenses, administrative and general expenses, or taxes other than income taxes that are allocated using other allocators (based on net or gross plant balances, wages and salaries, transmission operation and maintenance expenses,

[18] *Louisville Gas & Electric Co*., 106 FERC ¶ 63,039, at P 64 (2004), *aff'd*. 109 FERC ¶ 61,330 at P 8 (2004), reh'g denied, 111 FERC ¶ 61,323.

[19] *Louisville Gas & Electric Co.*, 109 FERC ¶ 61,330 (2004).

[20] *Louisville Gas & Electric Co*., 114 FERC ¶ 61,282, at P 197 (2006).

etc.) that indirectly incorporate the transmission plant allocator. This resulted in KU erroneously collecting amounts from wholesale power and transmission customers since it did not remove all costs associated with the Virginia distribution plant facilities from formula rate determinations.

Recommendations

We recommend that:

21. LG&E and KU should calculate the rate impact of recovering these costs in their stand-alone formula rate, and provide these calculations to the Division of Audits and Accounting.

22. For each year these Virginia distribution utility costs were included in their stand alone formula rate calculation, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate, calculated with interest under section 35.19a of the Commission's regulations.

6. Accounting for Cost of Removal

KU and LG&E improperly accounted for cost of removal on physical assets with legal asset retirement obligations.

Pertinent Guidance

18 C.F.R. pt. 101, Account 108, Accumulated Provision for Depreciation of Electric Utility plant (Major Only), states, in part:

> A. This account shall be credited with the following:
>
> (1) Amounts charged to account 403, Depreciation expense, or to clearing accounts for current depreciation expense for electric plant in service.
>
> (2) Amounts charged to account 403.1, Depreciation expense for asset retirement costs, for current depreciation expense related to asset retirement costs in electric plant in service in a separate subaccount.

E. The utility is restricted in its use of the accumulated provision of depreciation to the purposes set forth above. It shall not transfer any portion of this account … or make any other use thereof without authorization by the Commission.

Background

Audit staff examined KU and LG&E's cost of removal accounting for physical assets with legal asset retirement obligations, such as ash ponds, landfills, and coal storage facilities. KU and LG&E booked the cost of removal related to these assets by debiting Account 403, Depreciation Expense, and crediting Account 108, Accumulated Provision for Depreciation of Electric Utility Plant. KU and LG&E then reclassified these amounts to a regulatory liability account by debiting Account 108 and crediting Account 254, Other Regulatory Liabilities. Once KU and LG&E retired the asset and settled the ARO, KU and LG&E debited Account 254 and credited Account 108.

While KU and LG&E received state commission guidance from the Kentucky Public Service Commission that approved this accounting treatment, such approval does not dictate how this transaction should be accounted for under the Commission's accounting regulations. Under the Commission's accounting regulations, cost of removal is typically factored in the depreciation rate, and depreciation expense is accounted for in Accounts 403 and 108. According to the instructions to Account 108, amounts recorded herein must not be transferred to any other account absent of approval from the Commission. KU and LG&E did not seek nor receive approval from the Commission to transfer any amounts from Account 108. By transferring amounts initially recorded in Account 108 to Account 254, KU and LG&E did not follow the instructions for Account 108. For rate purposes, Account 108 is typically used to reduce rate base while amounts recorded in Account 254 are typically not used in the formula rate calculations. Since KU and LG&E removed these amounts from Account 108, it erroneously overstated rate base used to determine formula rate billings to transmission customers. Audit staff is aware that this accounting practice was used for years prior to the audit period.

Recommendations

We recommend that:

23. LG&E and KU should provide to the Division of Audits and Accounting correcting entries that show the reversal of amounts from Account 254.

24. For each year these amounts were included in their stand-alone formula rate, LG&E and KU should refund all costs, calculated with interest under section 35.19a of Commission regulations.

25. LG&E and KU should file a refund report with the Commission that reflects amounts refunded to their customers.

7. Merger Costs

PPL's three franchised public utilities (KU, LG&E, and PPL Electric) incorrectly included some transaction-related costs related to PPL's merger with E.ON U.S. in formula rate billings to wholesale power and transmission customers.[21]

Pertinent Guidance

The October 25, 2010 Commission order approving the merger of PPL and E.ON U.S., LLC stated:

> With respect to transaction-related costs, we accept Applicants' commitment to hold transmission and wholesale customers harmless from costs related to the transaction for a period of five years to the extent that such costs exceed savings related to the transaction, which we interpret to include all transaction-related costs, not only costs related to consummating the transaction.
>
> If Applicants seek to recover transaction-related costs through their wholesale power or transmission rates they must submit a compliance filing that details how they are satisfying the hold harmless requirement. If Applicants seek to recover transaction-related costs in an existing formula rate that allows for such recovery, then that compliance filing must be filed in the section 205 docket in which the formula rate was approved by the Commission, as well as in the instant section 203 docket. We also note that, if Applicants seek to recover transaction-related costs in a filing whereby they are proposing a new rate (either a new formula rate or a new stated rate), then that filing must be made in a new section 205 docket as well as in the instant section 203 docket. The Commission will notice such filings for public comment. In such filings, Applicants must: specifically identify the transaction-related costs they are seeking to recover, and (2) demonstrate that those costs are exceeded by the savings produced by the transaction, in addition to any requirements associated with filings made under section 205. Such a hold

[21] KU sells wholesale power to certain municipal utilities under long-term agreements that established cost-based wholesale power rates based on a formula rate. Moreover, PPL Electric, LG&E, and KU provide transmission service at formula rates.

> harmless commitment will protect customers' wholesale power and transmission rates from being adversely affected by the proposed transaction. [22]

Background

On June 28, 2010, PPL filed an application seeking authorization under sections 203(a)(1)(A), 203(a)(1)(B), and 203(a)(2) of the FPA for a proposed transaction in which PPL would acquire all of the issued and outstanding limited liability company interests of E.ON U.S. from E.ON AG's indirect, wholly owned subsidiary, E.ON U.S. Investments Corp. PPL sought to acquire E.ON U.S. for a purchase price of $7.625 billion, comprised of $2.062 billion in cash (subject to adjustment), the repayment of outstanding debt of E.ON U.S., LG&E, and KU estimated at $4.638 billion, and the assumption of $925 million in tax-exempt bonds of LG&E and KU. On October 25, 2010, the Commission issued an order approving the transaction under Docket No. EC10-77-000. [23] Audit staff evaluated PPL and its FPU subsidiaries for compliance with the conditions of this order. Besides reviewing Commission orders and company filings, understanding processes and procedures, and interviewing company staff, audit staff reviewed and tested compliance with the order's various provisions, such as verifying that the transaction did not result in any: (1) transfer of jurisdictional facilities between affiliated entities; (2) any securities issued for the benefit of any affiliated entity or in any new pledge or encumbrance of assets of an affiliated entity; or (3) any new affiliate contracts between affiliated entities. Audit staff also verified that all purchase accounting adjustment amounts were removed from account balances reported in the FERC Form No. 1.

Audit staff also evaluated compliance with the order's hold harmless provision, which required PPL to "hold transmission and wholesale customers harmless from costs related to the transaction for a period of five years to the extent that such costs exceed savings related to the transaction, which we interpret to include all transaction-related costs, not only costs related to consummating the transaction."

PPL properly excluded most of its transaction-related costs from formula rate billings to wholesale power and transmission customers, which included legal fees, consulting expenses, third-party costs, and internal labor costs. PPL had controls and procedures in place to hold harmless wholesale power and transmission customers, such as: payroll and time-reporting controls, communications from appropriate groups on how to charge certain costs, and supervisory review and approval of nonpayroll charges.

[22] *PPL Corporation*, 133 FERC ¶ 61,083, at PP 26-27 (2010).

[23] *Id.* P 1.

However, audit staff identified a small amount of transaction-related costs that flowed through to the formula rate billings.

In our review of transaction-related costs, audit staff determined that PPL's two service companies (PPL Services and LKS) allocated the most transaction-related costs to PPL ($113 million), LG&E & KU Capital ($32 million), and PPL Strategic Development ($1 million). These three entities held $146 million of the approximately $150 million in total transaction-related costs incurred during the audit period. The remaining $4 million of transaction-related costs were allocated to 12 other PPL entities, including PPL's 3 franchised public utilities, KU, LG&E, and PPL Electric, which are in bold in the table below. This table shows transaction costs allocated to each entity:

PPL Entity	Total Transaction Costs
1. PPL Corporation	$113,164,077
2. LG&E and KU Capital	$32,133,630
3. PPL Strategic Development	$1,262,186
4. PPL Global, LLC	$734,575
5. PPL Susquehanna LLC	$573,396
6. PPL Energy Services Holdings, LLC	$301,957
7. PPL Energy Plus, LLC	$298,902
8. PPL Generation LLC	$257,975
9. PPL Brunner Island, LLC	$222,337
10. PPL Montour LLC	$194,040
11. PPL Electric	**$163,329**
12. Louisville Gas & Electric	**$108,981**
13. Kentucky Utilities	**$95,060**
14. PPL Martins Creek, LLC	$58,814
15. PPL University Park, LLC	$24,408
Total	**$149,593,668**

In summary, PPL's three FPUs, KU, LG&E, and PPL Electric, were allocated approximately $367,000 in transaction-related costs, and they included approximately $329,229 of these costs in their wholesale power and transmission formula rate calculations. These costs consisted primarily of legal fees, consulting fees, wages of PPL staff in different departments, office supplies, and general and administrative expenses. These transaction-related costs included costs that were incurred before PPL filed its merger application with the Commission, during the transaction, and after the transaction was consummated. The Merger Order defines costs related to the transaction as "all transaction-related costs, not only costs related to consummating the transaction." The Merger Order also states, "If Applicants seek to recover transaction-related costs through their wholesale power or transmission rates they must submit a compliance filing that details how they are satisfying the hold harmless requirement. If Applicants seek to recover transaction-related costs in an existing formula rate that allows for such recovery, then that compliance filing must be filed in the section 205 docket in which the formula rate was approved by the Commission, as well as in the instant section 203 docket." PPL made no such filing to seek recovery for these costs.

Recommendations

We recommend that:

26. PPL Electric, LG&E, and KU should strengthen existing procedures so that no transaction-related costs flow through an FPU's formula rates.

27. PPL Electric, LG&E, and KU should calculate the rate impact of recovering transaction-related costs in their respective formula rates, and provide these calculations to the Division of Audits and Accounting.

28. PPL Electric, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate due to the incorrect allocation of transaction-related costs, calculated with interest in accordance to the Commission-approved formula rate protocols for PPL Electric and under section 35.19a of the Commission's regulations for LG&E and KU.

8. Allowance for Funds Used During Construction

KU's method of computing AFUDC on CWIP was deficient by compounding AFUDC monthly instead of semi-annually, including unrealized losses in its common equity balance used to calculate AFUDC, and using an incorrect balance for the common equity component.

Pertinent Guidance

AFUDC allows a company to recover its debt and equity costs used for funding construction. In Federal Power Commission's (FPC) Order No. 561, the Commission's predecessor agency, the FPC established a uniform formula for determining maximum rates to use for computing AFUDC.[24] The order states:

> The balances of long-term debt, preferred stock, and common equity for use in the formula for the current year will be the balances in such accounts at the end of the prior year; the cost rates for long-term debt and preferred stock will be the effective weighted average cost of such capital. The average short-term debt balances and related cost and the average construction work in progress balance will be estimated for the current year. We shall require, however, that public utilities and natural gas companies monitor their actual experience and adjust to actual at year-end if a significant deviation from the estimate should occur. For this purpose we shall consider a significant deviation to exist if the gross AFUDC rate exceeds by more than one-quarter of a percentage point (25 basis points) the rate that is derived from the formula by use of actual 13 monthly balances of construction work in progress and the actual weighted average cost and balances for short-term debt outstanding during the year.

On frequency of compounding of the AFUDC base, Order No. 561 states:

> We believe that a monthly compounding of AFUDC may result in excessive amounts capitalized since cash outlays for interest and dividends are not normally made on a monthly basis. We shall

[24] *Order Adopting Amendment to Uniform System of Accounts for Public Utilities and Licensees and for Natural Gas Companies*, Order No. 561, 57 FPC 608 (1977), *Order On Reh'g and Clarification*, Order 561-A, 59 FPC 1340 (1977), *further clarified*, 2 FERC ¶ 61,050 (1978).

> therefore permit compounding but no more frequently than semiannually.

18 C.F.R. pt. 101, Electric Plant Instruction 3 (17), Allowance for Funds Used During Construction, states in part:

> (a) Includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds.
>
> (b) The rates shall be determined annually. The balances for long-term debt, preferred stock and common equity shall be the actual book balances as of the end of the prior year … the short-term debt balances and related cost and the average balance for construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment, and fabrication shall be estimated for the current year with appropriate adjustments as actual data becomes available.

18 C.F.R. pt. 101, General Instruction 23 (C), Accounting for Other Comprehensive Income, states:

> (c) When it is probable that an item of other comprehensive income will be included in the development of cost-of-service rates in subsequent periods, that amount of unrealized losses or gains will be recorded in Accounts 182.3 or 254 as appropriate.

Background

AFUDC includes the net cost for the period borrowed funds were used for construction and a reasonable rate on other funds. KU recorded the balances below in Account 419.1, Allowance for Other Funds Used During Construction, and Account 432, Allowance for Borrowed Funds Used During Construction – Credit, during the audit period:

Year	Account 419.1	Account 432
2010	$521,152	$968,597
2011	$42,662	$12,955

Audit staff evaluated KU's AFUDC base and rate calculations, and the application of these calculations, to determine the accrual of AFUDC on CWIP for select construction projects. This evaluation identified several deficiencies with KU's AFUDC calculation methodology.

1. *AFUDC Compounded Monthly* – KU improperly compounded its AFUDC on a monthly basis. The Commission allows for compounding of AFUDC no more frequently than semi-annually.

2. *Unrealized Losses* – KU incorrectly included unrealized losses from Account 219, Accumulated Other Comprehensive Income (AOCI), in the common equity component of the AFUDC rate calculation. Specifically, KU recorded unrealized losses for its 20 percent ownership of Electric Energy, Inc.'s AOCI, which consisted of the unfunded portion of its pension and postretirement obligations. KU recorded Account 219 balances of ($2,854) and ($467,077) in 2010 and 2011, respectively. Accounting treatment for these unrealized losses was a debit to Account 219 and a credit to Account 123, Investment in Associated Companies (Major Only). Since these losses are unrealized and not used in determining KU's retained earnings, these amounts should not impact the amount of retained earnings used to calculate the AFUDC rate. Therefore, Account 219 should not be in the common equity component of the AFUDC calculation. However, it is appropriate for KU to include losses in determining the AFUDC rate once these amounts are realized, and enter retained earnings.

3. *Common Equity Balance* – KU input the wrong balance as the common equity component to its AFUDC calculation. For its 2010 AFUDC calculation, KU input the long-term debt amount of $1,648,779,405, instead of the common equity amount of $1,951,966,344, as found in the 2009 KU FERC Form No. 1 on line 16(c).

During the 2010 and 2011 years, KU accrued an aggregate amount of $1,545,366 in total AFUDC. Due to the above errors, this amount understated the correct actual amount, which was $1,550,647. The errors included overstatement effects of $290 and $305, due to the monthly compounding and inclusion of AOCI balance errors, respectively, offset by an understatement effect of $5,876 due to the common equity input error.

Recommendations

We recommend that:

29. KU should revise and implement procedures going forward to ensure its AFUDC base and rate calculation is consistent with Electric Plant Instruction 3(17) and other applicable Commission requirements.

9. Formula Rate Line References

KU and LG&E's formula rate Attachment O included multiple inaccurate line references.

Pertinent Guidance

Attachment O (Transmission Formula Rate) of KU and LG&E's OATT required formula rate inputs derived from FERC Form No. 1 amounts.

Background

During our review, audit staff determined that KU and LG&E's formula rate Attachment O included multiple inaccurate line references. Specifically, audit staff identified these incorrect line references:

Formula Rate Component	Att. O Reference	FERC Form No. 1 Line Item
Gross Plant in Service - Production	206.46g	205.46g
Gross Plant in Service - Transmission	206.58g	207.58g
Gross Plant in Service - Distribution	206.75g	207.75g
Gross Plant in Service - General & Intangible	206.5g and 206.90g	205.5g and 207.99g
Accumulated Depreciation - General & Intangible	219.27c	219.28c and 200.21c
Land Held For Future Use	214xd	Must specify line number
Materials & Supplies	227.8c and 227.15c	227.8c and 227.16c
O&M - Transmission	321.100b	321.112
O&M - Account 565	321.88b	321.96b
Depreciation Expense - General	336.10f	336.1f and 336.10f
Payroll Taxes	263i	Must specify line number
Highway and Vehicle Taxes	263i	Must specify line number
Property Taxes	263i	Must specify line number
Gross Receipts Taxes	263i	Must specify line number
Other Taxes	263i	Must specify line number
Wages & Salaries - Production	354.18b	354.20b
Wages & Salaries - Transmission	354.19b	354.21b
Wages & Salaries - Distribution	354.20b	354.23b
Wages & Salaries - Other	354.21, 22, 23b	354.24, 25, 27b
Proprietary Capital	112.15d	112.16d
Long term debt	112.18c-21c	112.18c-23c
Preferred Stock	112.3d	112.3c
Sales for Resale	311xh	Must specify page/line/column

Also, audit staff determined that KU and LG&E can improve the transparency of their formula rate calculations by better presenting all manual adjustments and purchase accounting adjustments that impact balances reported within Attachment O.

Recommendations

We recommend that:

30. LG&E and KU should develop and implement controls to ensure accurate and complete line references.

31. LG&E and KU should submit a filing with the Commission under FPA section 205 to address the incorrect formula rate line references.

10. FERC Form No. 60 Reporting

FERC Form No. 60 filings that PPL Services and LKS made contained several reporting errors relating to account misclassifications, supporting schedule discrepancies, and the reporting of convenience payments.

Pertinent Guidance

In 2006, centralized service companies became subject to the requirements of PUHCA 2005, which are incorporated into the Commission regulations in 18 C.F.R. pts. 366-369. The FERC Form No. 60 has specific reporting instructions for preparation of individual schedules and pages of the report. Regulations applicable to FERC Form No. 60 reporting by centralized service companies are:

18 C.F.R. section 366.23(a)(1), FERC Form No. 60, annual reports of centralized service companies, states, in part, "Every report must be submitted on the FERC Form No. 60 then in effect and must be prepared in accordance with the instructions incorporated into that form."

18 C.F.R. section 369(2)(ii), FERC Form No. 60, annual report of centralized service company, states in part, "The annual report in effect must be filed with the Commission as prescribed in Section 385.2011 of this chapter and as indicated in the General Instructions set out in the form, and must be properly completed and verified."

Background

Audit staff analyzed the FERC Form No. 60 filings made by PPL's two service companies – PPL Services and LKS. This analysis identified these reporting errors:

<u>900 Series Account Misclassifications</u>

PPL Services misclassified amounts reported on its 2010 FERC Form No. 60 for Accounts 920, Administrative and General Salaries, 921, Office Supplies and Expenses, and 923, Outside Services Employed. Specifically, PPL Services over-reported Account 920 by approximately $7 million, over-reported Account 921 by approximately $5 million, and under-reported Account 923 by approximately $12 million.

<u>Accounts 457.1, Regional Transmission Service Revenues, and 457.2, Miscellaneous Revenues, Reporting</u>

In its 2010 FERC Form No. 60, which reported only November and December 2010, PPL Services reported total billings of $67,368,843 on Schedule XVII – Analysis of Billing-Associate Companies. PPL Services then provided supporting documentation for total billings for November and December 2010 that totaled $68,300,671. This resulted in a variance of $931,828.

LKS identified adjustments in February 2010 for $138,642.20 and September 2010 for $1,426,588.45 in Account 457.1. For both months, both revenue and expenses were understated.

These errors occurred for various reasons, including administrative oversight, limited review procedures, and the absence of appropriate verification procedures.

<u>Convenience Payments</u>

Service companies report convenience payments on Schedule V of its FERC Form No. 60. Specifically, instruction 2 of Schedule V states:

> *If the service company has provided accommodation or convenience payments for associate companies, provide in a separate footnote a listing of total payments for each associate company.*

Audit staff reviewed convenience payment data from LKS. During this review, audit staff learned that some convenience payments, amounting to $252,448, were reflected on the 2010 income statement. These payments were recorded in Account 923, and were identified as having convenience payment expenditure types in error. Also, additional expenses, amounting to $1,570, were reflected as 2010 convenience payments and should not have been. Convenience payments should be charged only to balance sheet accounts and not income statement accounts. Therefore, these amounts were recorded in error. These errors caused no financial impact as they were included in both revenue and expense on the service company's income statement.

These errors were due to human error involving misclassification and improper recording of expenses. To address them, LKS developed and implemented a procedure to determine if convenience payments had been modified to use a more detailed review of transactions to be disclosed.

Recommendations

We recommend that:

32. LKS and PPL Services should develop and implement procedures to ensure proper account classification, consistent reporting, and completion of all supporting schedules of the FERC Form No. 60. As part of these procedures, incorporate an annual review to ensure the FERC Form No. 60 filed with the Commission is complete and accurate.

33. LKS and PPL Services should refile 2010 FERC Form No. 60, correcting all reporting errors within 90 days after this report is issued.

V. Other Matters

Formula Rate Recovery of Intangible Plant

KU and LG&E's formula rate under Attachment O of its joint OATT included templates for calculating rate base and cost-of-service components used to determine transmission formula rate billings. As relevant here, the Attachment O formula rate included a FERC Form No. 1 line reference for gross intangible plant in service. However, the Attachment O formula rate did not include a FERC Form No. 1 line reference for accumulated amortization related to intangible plant. Also, the Attachment O formula rate did not include a FERC Form No. 1 line reference for amortization expense of intangible plant. When KU and LG&E withdrew from MISO and began recovering their transmission revenue requirement under their joint OATT in March 2006, they adopted a formula rate that is substantially the same formula rate template in Attachment O to the MISO OATT, and carried over the same omissions related to intangible plant.

In October 2011, MISO and its transmission owners filed revisions to portions of the Attachment O formula rate, under FPA section 205**,** to clarify inclusion of intangible plant in the calculation of Attachment O revenue requirements under Docket No. ER12-297-000. The filing parties proposed to clarify the inclusion of intangible plant by adding the appropriate FERC Form No. 1 reference to intangible plant for the line item that contains accumulated depreciation on general and intangible plant. The filing parties also proposed to add the language "and Amortization" to the column heading for "Depreciation Expense" and add the language "and Intangible" to the line item for "General" depreciation and amortization expense. Finally, the filing parties proposed to add the appropriate FERC Form No. 1 reference for amortization expense of intangible plant. On December 21, 2011, the Commission accepted MISO's submittal for filing.

During audit fieldwork, audit staff pointed out that KU and LG&E's formula rate under its joint OATT continues to have omissions related to intangible plant that were identified and corrected in Docket No. ER12-297-000. Since KU and LG&E now recover their cost of service based on a formula rate substantially the same as the MISO formula rate, they should have made a filing with the Commission under FPA section 205, similar to what MISO and its transmission owners did in ER12-297-000, to address the proper recovery of intangible plant.

Specifically, in calculating the revenue requirement for the transmission formula rate, KU and LG&E included intangible plant assets recorded in Accounts 301, Organization, 302, Franchise and Consents, and 303, Miscellaneous Intangible Plant, as components of its rate base. However, KU and LG&E did not reduce any of these amounts by any related corresponding amortization recorded in Account 111, Accumulated Provision for Amortization of Electric Plant.

Recommendation

We recommend that:

LG&E and KU submit a filing with the Commission under FPA section 205 to adopt the revisions for intangible plant MISO proposed in Docket No. ER12-297-000 and incorporate them into KU and LG&E's formula rate template under their joint OATT.

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September 26, 2014

Bryan K. Craig
Director and Chief Accountant, Division of Audits and Accounting
Federal Energy Regulatory Commission
888 First Street N.E. - Room 5K-13
Washington, DC 20425

Re: PPL Corporation, Docket No. FA12-12-000
Comments on Draft Audit Report

Dear Mr. Craig:

PPL Corporation ("PPL") appreciates this opportunity to comment on the September 11, 2014 Draft Audit Report provided to PPL by the Division of Audits and Accounting of the Office of Enforcement of the Federal Energy Regulatory Commission ("DAA") relating to an audit conducted in the above-referenced docket (the "Draft Audit Report"). PPL agrees with the findings and accepts the recommendations contained in the Draft Audit Report.

In many cases, PPL already has completed implementation or begun implementation of corrective measures related to the audit findings. Attachment A to this letter explains the corrective actions taken or planned, and provides actual or target completion dates for these actions.

PPL wishes to thank DAA personnel involved in the audit for their professionalism and courtesy.

Sincerely,

Vincent Sorgi

Attachment

Attachment A

I. Draft Audit Report Section IV. Findings and Recommendation

1. Long-Term Investment in Subsidiary

Recommendation 1 - PPL Electric should provide notice of its material accounting changes to its wholesale transmission customers as required by section III.B of Attachment H-8H, Formula Rate Implementation Protocols, of its Open Access Transmission Tariff.

Corrective Action: On May 15, 2014, PPL Electric filed its 2014 Annual Update with the Federal Energy Regulatory Commission ("Commission") in Docket No. ER09-1148 pursuant to the Formula Rate Implementation Protocols of its Open Access Transmission Tariff. The Commission publicly posted the filing on its eLibrary system the same day. Therein, PPL Electric explained that it changed its method of accounting for the activities of its subsidiary PPL Receivables Corporation from the consolidated method of accounting to the equity method of accounting in accordance with the Commission's regulations and that the changes affected PPL Electric's 2009 through 2013 Rate Years, given that the formula rate was first implemented on November 1, 2008. PPL Electric served the 2014 Annual Update on all parties to the docket on May 15, 2014, and provided a copy to its Regional Transmission Organization, PJM Interconnection, L.L.C. ("PJM") for posting on the PJM website. This action is completed.

Recommendation 2 - PPL Electric should implement procedures to ensure that it follows the equity method of accounting for all investments in subsidiaries and ensure no deviation between accounting practices and Commission accounting regulations.

Corrective Action 1: By November 30, 2014, PPL Electric will finalize its policy related to the differences in FERC and Securities and Exchange Commission ("SEC") reporting. Included in this policy will be a discussion of the accounting for investments in subsidiaries using the equity method of accounting and recording those investments in Account 123.1, Investment in Subsidiary Companies, for FERC reporting purposes, consistent with the FERC's accounting guidelines.

Corrective Action 2: In December 2013, PPL Electric implemented a new methodology that involves reviewing and cataloging electric industry-wide FERC Audit Report findings to ensure that PPL Electric appropriately reflects the accounting for similar transactions identified in such audit findings. The associated database is updated quarterly.

Corrective Action 3: On November 8, 2013, PPL Corporation modified its Journal Entry policy and procedures to specifically state that the impact on rate making mechanisms be considered for all journal entries affecting the domestic regulated utilities within the PPL family of companies.

Corrective Action 4: PPL Electric, together with PPL Services, will establish enhanced senior management-level procedures for on-going communication and oversight of company analysis and implementation of FERC developments related to accounting procedures and transmission formula rate calculations. This is expected to be completed within 90 days of the issuance of a final audit report.

Recommendation 3 - PPL Electric should adopt controls that will ensure all costs related to PPL Receivables' operating activities are excluded from all components in PPL Electric's formula rate calculation.

Corrective Action 1: By November 30, 2014, PPL Electric will finalize its policy related to the differences in FERC and SEC reporting. Included in this policy will be a discussion of the accounting for investments in subsidiaries using the equity method of accounting and recording those investments in Account 123.1, Investment in Subsidiary Companies, for FERC reporting purposes, consistent with the FERC's accounting guidelines.

Corrective Action 2: PPL Electric has modified its reporting of PPL Receivables in FERC Form 1 to use the equity method of accounting. PPL Electric utilizes the FERC Form 1 as the basis for its formula rate inputs. By reporting PPL Receivables using the equity method, PPL Electric will no longer include PPL Receivables' operating activities in the formula rate calculation.

Recommendation 4 - PPL Electric should refund all costs incorrectly included in and recovered through the formula rate since its inception, with interest, calculated in accordance with the formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

Corrective Action: In accordance with Section VII of PPL Electric's Formula Rate Implementation Protocols, PPL Electric refunded the costs to properly account for PPL Receivables Corporation using the equity versus consolidated method of accounting recovered through the formula rate since its inception, with interest, as detailed in its 2014 Annual Update filed on May 15, 2014 with the Commission. The changes to the revenue requirement detailed in the 2014 Annual Update took effect in the 2014 rate year, which began on June 1, 2014 and ends on May 31, 2015.

Recommendation 5 - PPL Electric should file a refund report with the Commission that reflects amounts refunded to PPL Electric's wholesale transmission customers.

Corrective Action: PPL Electric expects to file a refund report within 90 days of the issuance of a final audit report.

2. ***Tax Overpayments***

Recommendation 6 - PPL Electric should reclassify federal and state income taxes recorded in Account 165, Prepayments, applicable to those years in which PPL Electric chose to receive a refund of those amounts to Account 146, Accounts Receivable from Associated Companies or Account 143, Other Accounts Receivable, as appropriate.

Corrective Action: PPL Electric reclassified federal and state income tax overpayments to the appropriate receivable accounts for the 2011 and 2012 balance sheets and for supporting pages of the 2012 FERC Form I Restatement filed on October 29, 2013. PPL Electric also reclassified federal and state income tax overpayments to the appropriate receivable accounts for rate years 2009-2013 and refunded the reduction in the revenue requirement, with interest, that resulted from including overpayments as receivables rather than prepayments as explained in the 2014 Annual Update filed with the Commission in May 15, 2014.

Recommendation 7 - PPL Electric should submit correcting entries to the Division of Audits and Accounting within 30 days of this report.

Corrective Action: PPL Electric will submit correcting entries to DAA within 30 days of the date of the issuance of the final audit report.

Recommendation 8 - PPL Electric should revise procedures to ensure its income tax transactions recorded to Account 165 represent actual prepayments.

Corrective Action 1: PPL Electric revised procedural documentation to explain the accounting of federal and state income tax overpayments on November 25, 2013. PPL Electric also implemented an automated process that will no longer reclassify federal and state income tax overpayments to Account 165, which began with the December 31, 2013 accounting close.

Corrective Action 2: In addition, as this is an area where FERC accounting differs from SEC accounting, the policy relating to differences in FERC and SEC reporting that is referenced in Corrective Action 1 of Recommendation 2 will make reference to this issue. That policy will be completed by November 30, 2014.

Recommendation 9 - PPL Electric should revise procedures to appropriately determine its tax accrual amount.

Corrective Action: PPL Electric has revised its procedures to properly reclassify income tax overpayments, determined through its accrual and payment process, recorded in Account 236 to either Account 143 or Account 146. See corrective action to Recommendation 8.

Recommendation 10 - PPL Electric should record the necessary correcting entries as of December 31 to reflect the proper accounting for Federal and state estimated tax overpayment.

Corrective Action: PPL Electric has completed this as part of the corrective actions discussed in response to Recommendation 6 above.

Recommendation 11 - For each year these amounts were included in the formula rate calculations, PPL Electric should refund all costs incorrectly included in and recovered through the formula rate, with interest, calculated pursuant to its formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

Corrective Action: In accordance with Section VII of PPL Electric's Formula Rate Implementation Protocols, PPL Electric refunded the costs incorrectly included in and recovered through the formula rate since its inception, with interest, as detailed in its 2014 Annual Update filed on May 15, 2014 with the Commission. The changes to the revenue requirement detailed in the 2014 Annual Update took effect in the 2014 rate year, which began on June 1, 2014 and ends on May 31, 2015.

Recommendation 12 - PPL Electric should file a refund report with the Commission that reflects amounts refunded to PPL Electric's wholesale transmission customers.

Corrective Action: PPL Electric expects to file a refund report within 90 days of the issuance of a final audit report.

3. *Manufactured Gas Plant Obligations*

Recommendation 13 - PPL Electric should amend its accounting policies to ensure manufactured gas plant remediation expenses are accounted for consistent with the Commission's accounting regulations.

Corrective Action: As referenced in Corrective Action 1 of Recommendation 2, PPL Electric will finalize its policy related to the differences in FERC and SEC reporting by November 30, 2014. Included in this policy is a discussion of the recording of manufactured gas site remediation expenses to Account 426.5, Other Deductions, for FERC reporting purposes, consistent with the FERC's accounting guidelines.

Recommendation 14 - PPL Electric should refrain from including manufactured gas plant remediation expenses in the formula rate determinations, since such costs were not incurred in providing service to wholesale transmission customers.

Corrective Action: PPL Electric provided notice of its accounting change relating to Manufactured Gas Plant costs in its 2014 Annual Update filed with the Commission on May 15, 2014 and will refrain on an ongoing basis from including these costs in its formula rate determinations based on the Division of Audits and Accounting's view that such costs were not incurred in providing service to wholesale transmission customers.

Recommendation 15 - PPL Electric should determine the amount of manufactured gas plant remediation expenses recovered through its formula rate.

Corrective Action: In September 2014, PPL Electric provided to DAA as Attachment 19 the amount of MGP environmental remediation expenses recovered through PPL Electric's transmission formula rate.

Recommendation 16 - For each year affected, PPL Electric should refund the manufactured gas plant remediation expense amounts improperly included and recovered through the formula rate, calculated pursuant to its formula rate protocols approved by the Commission through the formula rate true-up process in 2014.

Corrective Action: In accordance with Section VII of PPL Electric's Formula Rate Implementation Protocols, PPL Electric refunded the manufactured gas plant remediation expenses improperly included in and recovered through the formula rate since its inception, with interest, as detailed in its 2014 Annual Update filed on May 15, 2014 with the Commission. The changes to the revenue requirement detailed in the 2014 Annual Update took effect in the 2014 rate year, which began on June 1, 2014 and ends on May 31, 2015.

Recommendation 17 - PPL Electric should file a refund report with the Commission that reflects amounts refunded to its wholesale transmission customers.

Corrective Action: PPL Electric expects to file a refund report within 90 days of the issuance of a final audit report.

4. *Asset Retirement Obligation*

Recommendation 18 - LG&E and KU should submit a filing with the Commission under FPA section 205 to address their recovery of asset retirement obligation costs.

Corrective Action: LG&E and KU anticipate that they will submit the recommended FPA Section 205 filing relating to the recovery of asset retirement obligations within 90 days of the issuance of a final audit report.

Recommendation 19 - LG&E and KU should calculate the rate impact of recovering these ARO costs in the formula rate, and provide these calculations to the Division of Audits and Accounting.

Corrective Action: In September 2014, LG&E and KU provided estimated rate impact calculations (interest through June 2014) regarding the consolidated anticipated audit findings, including ARO costs, and certain rate under-billings to the Division of Audits and Accounting. LG&E and KU anticipate that they will provide to DAA and file with the Commission for approval a report showing updated consolidated rate impact calculations, including ARO costs, (through a then-current date) within 60 days following issuance of a final audit report. Thereafter, LG&E and KU anticipate that they will provide to DAA and file with the Commission for approval a report showing rate impacts for any final or remaining period of ARO cost recovery within 60 days following effectiveness of new rates pursuant to the FPA section 205 proceeding.

Recommendation 20 - For each year affected since the inception of their stand-alone formula rate, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate due to recovering asset retirement obligation costs, calculated with interest under § 35.19a of the Commission's regulations.

Corrective Action: LG&E and KU will refund or credit to ratepayers amounts inappropriately recovered through the transmission formula rate during such period due to recovering asset retirement obligation costs with interest, and anticipate that they will do so within 30 days of each applicable final Commission order accepting the respective refund reports filed in response to Recommendation 19.

5. ***Virginia Distribution Utility Plant Costs***

Recommendation 21 - LG&E and KU should calculate the rate impact of recovering these costs in their stand-alone formula rate, and provide these calculations to the Division of Audits and Accounting.

Corrective Action: In September 2014, LG&E and KU provided estimated rate impact calculations (with interest through June 2014) regarding the consolidated anticipated audit findings, including Virginia distribution plant costs, and certain rate under-billings to the Division of Audits and Accounting. LG&E and KU anticipate that they will provide to DAA and file with the Commission for approval a report showing updated consolidated rate impact calculations, including Virginia distribution plant costs, (through a then-current date) within 60 days following issuance of a final audit report.

Recommendation 22 - For each year these Virginia distribution utility costs were included in their stand alone formula rate calculation, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate, calculated with interest under § 35.19a of the Commission's regulations.

Corrective Action: In connection with LG&E and KU's 2012 Annual Update for rates effective in the 2012 rate year which began on June 1, 2013 and ended on May 31, 2014, LG&E and KU corrected the inputs for Virginia plant so that costs associated with Virginia distribution utility plant no longer would flow through the formula rate. LG&E and KU will refund or credit to ratepayers amounts recovered through the transmission formula rate during such period associated with Virginia plant distribution costs with interest and anticipate that they will do so within 30 days of each applicable final Commission order accepting the refund report filed in response to Recommendation 21.

6. ***Accounting for Cost of Removal***

Recommendation 23 - LG&E and KU should provide to the Division of Audits and Accounting correcting entries that show the reversal of amounts from Account 254.

Corrective Action: As part of the August 2013 accounting close, LG&E and KU corrected their accounting entries for cost of removal. Effective with

LG&E and KU's 2013 Annual Update for rates effective in the 2013 rate year which began on June 1, 2014 and ends on May 31, 2015, LG&E and KU's formula rate no longer included rate impacts from such cost of removal accounting. LG&E and KU will file such correcting entries showing the reversal of amounts from Account 254 within 30 days of the issuance of the final audit report.

Recommendation 24 - For each year these amounts were included in their stand-alone formula rate, LG&E and KU should refund all costs, calculated with interest under section 35.19a of Commission regulations.

<u>Corrective Action</u>: LG&E and KU will refund or credit to ratepayers amounts recovered through the transmission formula rate during such period due to cost of removal with interest and anticipate that they will do so within 30 days of each applicable final Commission order accepting the refund report filed in response to Recommendation 25.

Recommendation 25 - LG&E and KU should file a refund report with the Commission that reflects amounts refunded to their customers.

<u>Corrective Action</u>: In September 2014, LG&E and KU provided estimated rate impact calculations (interest through June 2014) regarding the consolidated anticipated audit findings, including cost of removal, and certain rate under-billings to the Division of Audits and Accounting. LG&E and KU anticipate that they will provide to DAA and file with the Commission for approval a report showing updated consolidated rate impact calculations including cost of removal (through a then-current date) within 60 days following issuance of a final audit report.

7. <u>Merger Costs</u>

Recommendation 26 - PPL Electric, LG&E and KU should strengthen existing procedures so that no transaction-related costs flow through an FPU's formula rates.

<u>Corrective Action 1</u>: PPL Corporation made organizational changes in 2011 to create PPL Strategic Development, LLC for the Strategic Development group, the group that coordinates merger and acquisition ("M&A") activities and bears the costs of these activities. This organizational change has made it easier to direct M&A charges to the proper business unit and thereby exclude them from the regulated entities.

<u>Corrective Action 2</u>: PPL Services has improved communications among the Strategic Development group, Office of General Counsel, the Financial

Department and other appropriate groups within PPL Corporation in an effort to establish proper accounting for M&A projects at the onset of such projects by:

a) Reviewing the FERC audit with budget coordinators and reemphasizing the need for stronger controls and accurate accounting for costs associated with Strategic Development acquisition and divesture activities. (completed December 2012).
b) Drafting and reviewing with budget coordinators the proposed Accounting Policy and Procedures for Costs Associated with Acquisitions and Divestures. (completed April 2014).
c) Issuing an email communication to budget coordinators instructing them how to charge transaction and transition costs related to the spinoff of PPL Corporation Supply Segment. (completed June 2014).
d) Conducting meetings with key individuals for the purpose of discussing and reviewing issues related to proper charging of PPL Corporation Supply Segment spinoff costs. (completed July and August, 2014).
e) Issuing the Accounting Policy and Procedures for Costs Associated with Acquisitions and Divestures and communicating said issuance to all budget coordinators. (completed August 2014).
f) Developing and issuing a message to all PPL Corporation supervisors to emphasize the importance of properly capturing all costs related to the spinoff of PPL Corporation Supply Segment. (completed September 2014).

Corrective Action 3: As of August 2014, PPL Services' Financial and Accounting Departments developed an accounting policy/procedure related to M&A activities and included it with other accounting policies and procedures on the Controller's Department Accounting Policies and Procedures intranet web site.

Corrective Action 4: PPL Services will include a summary of the M&A accounting policy in the Cost Allocation Manual during the next update by December 31, 2014.

Corrective Action 5: Commencing with LG&E and KU's 2013 Annual Update for rates effective in the 2013 rate year which began on June 1, 2014 and ends on May 31, 2015, LG&E and KU no longer included rate impacts from such transaction-related costs.

Corrective Action 6: During September 2013, LG&E and KU modified their Regulatory Compliance accounting policy to provide additional guidance on merger costs. Examples of merger transaction and transition costs were included in this accounting policy.

Corrective Action 7: During September 2013, LG&E and KU updated its "Merger Transaction and Transition Cost" accounting treatment guidance on the Company's intranet site with information regarding how merger transaction and transition costs are to be handled.

Recommendation 27 - PPL Electric, LG&E and KU should calculate the rate impact of recovering transaction-related costs in their respective formula rates, and provide these calculations to the Division of Audits and Accounting.

Corrective Action 1: In September 2014, LG&E and KU provided estimated rate impact calculations (interest through June 2014) regarding the consolidated anticipated audit findings, including transaction-related costs, and certain rate under-billings to DAA. LG&E and KU anticipate that they will provide to DAA and file with the Commission for approval a report showing updated consolidated rate impact calculations regarding transaction-related costs (through a then-current date) within 60 days following issuance of a final audit report.

Corrective Action 2: In September 2014, PPL Electric provided DAA with Attachment 1 that identifies the rate impact of recovering transaction-related costs through PPL Electric's transmission formula rate.

Recommendation 28 - PPL Electric, LG&E and KU should refund to ratepayers amounts inappropriately recovered through the transmission formula rate due to the incorrect allocation of transaction-related costs, calculated with interest in accordance to the Commission-approved formula rate protocols for PPL Electric and under § 35.19a of the Commission's regulations for LG&E and KU.

Corrective Action 1: LG&E and KU will refund or credit to ratepayers amounts recovered through the transmission formula rate due to such transaction-related costs, with interest, and anticipate that they will do so within 30 days of each applicable final Commission order accepting the respective refund report filed in response to Recommendation 27.

Corrective Action 2: In accordance with Section VII of PPL Electric's Formula Rate Implementation Protocols, PPL Electric refunded the transaction-related costs improperly included in and recovered through the formula rate since its inception, with interest, as detailed in its 2014 Annual Update filed on May 15, 2014 with the Commission. The changes to the revenue requirement detailed in the 2014 Annual Update took effect in the 2014 rate year, which began on June 1, 2014 and ends on May 31, 2015.

8. ***Allowance for Funds Used During Construction***

Recommendation 29 - KU should revise and implement procedures going forward to ensure its AFUDC base and rate calculation is consistent with Electric Plant Instruction 3(17) and other applicable Commission requirements.

Corrective Action 1: Beginning with the February 2012 accounting close, KU modified its PowerPlant fixed asset accounting system to properly account for AFUDC. The PowerPlant automated AFUDC calculation was updated to compound interest semiannually rather than monthly.

Corrective Action 2:
During August 2012, KU finalized modifications to its AFUDC accounting policy and procedures to record AFUDC in accordance with Electric Plant Instruction 3(17) and Federal Power Commission Order 561.

9. ***Formula Rate Line References***

Recommendation 30 - LG&E and KU should develop and implement controls to ensure accurate and complete line references.

Corrective Action: During 2012 and 2013, LG&E and KU developed and implemented, enhanced controls and procedures for the transmission formula rate template to ensure appropriate references going forward, similar to Sarbanes-Oxley–level controls. LG&E and KU strengthened spreadsheet controls on the formula rate template, such as password protection, increased automation and protection for calculations, clearly labeled input data entry, and increased internal cross-check features. LG&E and KU implemented written process documentation and a narrative for the controls describing the specific procedures and responsibilities for calculating and reviewing the transmission formula rate relating to calculation performed by its Rates Department, reviews performed by its Rates, Accounting, and Transmission Departments and sign-off at the senior management level prior to posting.

Recommendation 31 - LG&E and KU should submit a filing with the Commission under FPA section 205 to address the incorrect formula rate line references.

Corrective Action: LG&E and KU anticipate that they will submit the recommended FPA Section 205 filing(s) relating to incorrect formula rate line references within 90 days of the issuance of a final audit report.

10. FERC Form No. 60 Reporting

Recommendation 32 - LKS and PPL Services should develop and implement procedures to ensure proper account classification, consistent reporting, and completion of all supporting schedules of the FERC Form No. 60. As part of these procedures, incorporate an annual review to ensure the FERC Form No. 60 filed with the Commission is complete and accurate.

Corrective Action 1: In March 2012, during preparation for the 2012 Form 60 filing, LG&E and KU developed a query within its Oracle financial system to better identify and capture LKS intercompany transactions that should be distinguished as convenience payments. Further enhancements were made to this query throughout 2013 to improve the efficiency of the query and to reduce manual adjustments to identify the convenience payments. In January and February 2013 LG&E and KU set up additional expenditure types within Oracle to also aid in identifying convenience payments.

Corrective Action 2: In November 2012, LG&E and KU developed a document to further educate employees on the identification of convenience payments. This document, along with a decision tree, has been shared with all employees via their intranet site.

Corrective Action 3: PPL Services implemented an automated process in 2012, using delivered allocation functionality in its general ledger software. The automated process performs the reclassification among Accounts 920, 921 and 923 based on cost type. The automated process mirrors the manual reclassification journal entries reflected in the 2011 FERC Form 60. As an additional control for PPL Services, beginning in 2012, the cost types in accounts 920, 921, and 923 are reviewed on a monthly basis to ensure that amounts are appropriately classified in these accounts.

Corrective Action 4: PPL Services developed written procedures for the preparation of Form 60. Prior to the filing of the 2013 Form 60 which occurred on April 30, 2014, Corporate Audit Services reviewed the process for preparing PPL Services' Form 60, the procedures used to allocate cost in the 2013 Form 60, and the completeness and accuracy of the 2013 Form 60. Management has requested Corporate Audit Services to include a review of the Form 60 in its audit plan.

Recommendation 33 - LKS and PPL Services should refile 2010 FERC Form No. 60, correcting all reporting errors within 90 days after this report is issued.

Corrective Action 1: LKS will refile the 2010 FERC Form No. 60 within 90 days of the date the final audit report is issued.

Corrective Action 2: PPL Services will refile the 2010 FERC Form No. 60 within 90 days of the date the final audit report is issued.

II. **Draft Audit Report Section V. Other Matters**

Formula Rate Recovery of Intangible Plant

Recommendation - LG&E and KU submit a filing with the Commission under FPA section 205 to adopt the revisions for intangible plant MISO proposed in Docket No. ER12-297-000 and incorporate them into KU and LG&E's formula rate template under their joint OATT.

Corrective Action: LG&E and KU anticipate that they will submit the recommended FPA Section 205 filing(s) adopting revisions for intangible plant as proposed by MISO and incorporating those changes into the formula rate template under their joint OATT within 90 days of the issuance of a final audit report.

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(j)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

The prospectuses of the most recent stock or bond offerings.

Response:

See attached.

NEW ISSUE **BOOK-ENTRY-ONLY**

Subject to the conditions and exceptions set forth under the heading "Tax Treatment," Bond Counsel is of the opinion that, under current law, interest on the Bonds offered hereby will be excludable from the gross income of the recipients thereof for federal income tax purposes, except that no opinion will be expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" or a "related person" of the Project as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on the Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. The alternative minimum tax has been repealed with respect to corporations for taxable years beginning after December 31, 2017. 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 is further of the opinion that interest on the Bonds will be excludable from the gross income of the recipients thereof for Kentucky income tax purposes and that, under current law, the principal of the Bonds will be exempt from ad valorem taxes in Kentucky. Issuance of the Bonds is subject to receipt of a favorable tax opinion of Bond Counsel as of the date of delivery of the Bonds. See "Tax Treatment" herein.

$17,875,000
County of Carroll, Kentucky
Environmental Facilities Revenue
Refunding Bonds
2018 Series A
(Kentucky Utilities Company Project)

Dated: Date of original delivery
Interest Payment Dates: June 1 and December 1

Due: February 1, 2026
Iuterest Rate: 3.375%

The County of Carroll, Kentucky, Environmental Facilities Revenue Refunding Bonds, 2018 Series A (Kentucky Utilities Company Project) (the "Bonds") will be special and limited obligations of the County of Carroll, Kentucky (the "Issuer"), payable by the Issuer solely from and secured by payments to be received by the Issuer pursuant to a Loan Agreement with Kentucky Utilities Company (the "Company"), except as payable from proceeds of such Bonds or investment earnings thereon. The Bonds will 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.

Principal of, and interest on, the Bonds are further secured by the delivery to U.S. Bank National Association, as Trustee, of First Mortgage Bonds of

KENTUCKY UTILITIES COMPANY

The Bonds will bear interest at the Long Term Rate of 3.375% per annum from the date of issuance to maturity, subject to earlier conversion or redemption as described herein. Interest on the Bonds will be payable on each June 1 and December 1, commencing December 1, 2018. The interest rate period, interest rate and interest rate mode will be subject to change under certain conditions, as described in this Official Statement. The Bonds will be subject to optional redemption on and after December 1, 2023, and will be subject to extraordinary optional redemption and mandatory redemption following a determination of taxability prior to maturity, as described in this Official Statement.

PRICE: 100%

The Bonds, when issued, will be 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. Purchases of beneficial ownership interests in the Bonds will be made in book-entry only form in denominations of $5,000 and multiples thereof. Purchasers will not receive certificates representing their beneficial interests in the Bonds. See the information contained under the heading "Summary of the Bonds — Book-Entry-Only System" in this Official Statement. The principal or redemption price of and interest on the Bonds will be paid by U.S. Bank National Association, 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 herein.

The Bonds are offered when, as and if issued and received by the Underwriter, subject to prior sale, withdrawal or modification of the offer without notice, and to the approval of legality by Stoll Keenon Ogden PLLC, Louisville, Kentucky, as Bond Counsel and upon satisfaction of certain conditions. Certain legal matters will be passed upon for the Company by its counsel, Jones Day, Chicago, Illinois and John R. Crockett III, General Counsel, Chief Compliance Officer and Corporate Secretary of the Company, for the Issuer by its County Attorney, and for the Underwriter by its counsel, McGuireWoods LLP, Chicago, Illinois. It is expected that the Bonds will be available for delivery to DTC in New York, New York on or about September 5, 2018.

US Bancorp

Dated: August 28, 2018

The Bonds are exempt from registration under the Securities Act of 1933, as amended.

No dealer, broker, salesman or other person has been authorized by the Issuer, the Company or the Underwriter to give any information or to make any representation with respect to the Bonds, other than those contained in this Official Statement, 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 Underwriter has provided the following sentence for inclusion in this Official Statement. The Underwriter has reviewed the information in this Official Statement in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriter does not guarantee the completeness of such information. The information and expressions of opinion in this Official Statement are subject to change without notice and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the parties referred to above since the date hereof.

In connection with the offering of the Bonds, the Underwriter may over-allot or effect transactions which stabilize or maintain the market prices of such Bonds at levels above those which 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 OFFERING, 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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OFFICIAL STATEMENT

$17,875,000
County of Carroll, Kentucky
Environmental Facilities Revenue
Refunding Bonds
2018 Series A
(Kentucky Utilities Company Project)

Introductory Statement

This Official Statement, including the cover page and Appendices, is provided to furnish information in connection with the offer and sale by the County of Carroll, Kentucky (the "Issuer") of its Environmental Facilities Revenue Refunding Bonds, 2018 Series A (Kentucky Utilities Company Project), in the aggregate principal amount of $17,875,000 (the "Bonds") to be issued pursuant to an Indenture of Trust dated as of August 1, 2018 (the "Indenture") between the Issuer and U.S. Bank National Association (the "Trustee"), as Trustee, Paying Agent and Bond Registrar.

Pursuant to a Loan Agreement by and between Kentucky Utilities Company (the "Company") and the Issuer, dated as of August 1, 2018 (the "Loan Agreement"), proceeds from the sale of the Bonds, other than accrued interest, if any, paid by the initial purchasers thereof, will be loaned by the Issuer to the Company.

The proceeds of the Bonds (other than any accrued interest) will be applied in full, together with other moneys made available by the Company, to pay and discharge all of the $17,875,000 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2007 Series A (Kentucky Utilities Company Project) (the "2007 Bonds"), previously issued by the Issuer to finance certain solid waste disposal facilities (the "Project") owned by the Company. For information regarding the solid waste disposal facilities, see "The Project."

It is a condition to the Underwriter's obligation to purchase the Bonds that the Company irrevocably instruct the trustee in respect of the 2007 Bonds, on or prior to the date of issuance of the Bonds, to call the 2007 Bonds for redemption.

The Company will repay the loan under the Loan Agreement by making payments to the Trustee in sufficient amounts to pay the principal or redemption price of and interest on the Bonds and will further agree under the Loan Agreement to make payments of the purchase price of the Bonds tendered for purchase to the extent funds are not otherwise available under the Indenture. 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 rights to indemnification, reimbursement, notice and payment of expenses) will be assigned to the Trustee as security for the Bonds.

For the purpose of further securing the Bonds, the Company will issue and deliver to the Trustee a series of the Company's First Mortgage Bonds, Collateral Series 2018CCA (the "First Mortgage Bonds"). The principal amount, maturity date and interest rate (or method of determining interest rates) of such First Mortgage Bonds will correspond 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 and the First

Mortgage Indenture." 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 will be issued under, and will be secured by, the Company's Indenture, dated as of October 1, 2010, as previously supplemented and as to be supplemented by a supplemental indenture to be dated as of August 1, 2018 relating to the Bonds (the "First Mortgage Supplemental Indenture," and the Indenture, as so supplemented, the "First Mortgage Indenture"), between the Company and The Bank of New York Mellon, as trustee (the "First Mortgage Trustee").

The Company is a wholly-owned subsidiary of LG&E and KU Energy LLC and an indirect wholly-owned subsidiary of PPL Corporation. The Company's obligations under the Loan Agreement are solely its own, and not those of any of its affiliates. None of PPL Corporation or the Company's other affiliates will be obligated to make any payments due under the Loan Agreement or First Mortgage Bonds or any other payments of principal, interest, redemption price or purchase price of the Bonds.

The Bonds will be special and limited obligations of the Issuer, and the Issuer's obligation to pay the principal or redemption price of and interest on, and purchase price of, the Bonds will be limited solely to the revenues and other amounts received by the Trustee under the Indenture pursuant to the Loan Agreement, including amounts payable on the First Mortgage Bonds. The Bonds will not constitute an indebtedness, general obligation or pledge of the faith and credit or taxing power of the Issuer, the Commonwealth of Kentucky or any political subdivision thereof.

Brief descriptions of the Company, the Issuer, the Bonds, the Loan Agreement, the Indenture, the First Mortgage Bonds and the First Mortgage Indenture are included in this Official Statement. 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 completeness. All references in this Official Statement to the documents are qualified in their entirety by reference to such documents, and references in this Official Statement to the Bonds are qualified in their entirety by reference to the definitive form of the Bonds 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 and, until the issuance of the Bonds, may be obtained from the Underwriter. The First Mortgage Indenture (including the form of the First Mortgage Bonds) is available for inspection at the office of the Company in Lexington, Kentucky, and at the corporate trust office of the First Mortgage Trustee, in Pittsburgh, Pennsylvania. Certain information relating to The Depository Trust Company ("DTC") and the book-entry-only system has been furnished by DTC. Appendix A to this Official Statement and all information contained under the headings "The Project" and "Use of Proceeds" 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. The Underwriter has reviewed the information in Appendix A to this Official Statement in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriter does not guarantee the completeness of such Appendix A or such information. Appendix B to this Official Statement contains the proposed form of opinion of Bond Counsel to be delivered in connection with the issuance and delivery of the Bonds.

This Official Statement only describes the terms and provisions applicable to the Bonds while accruing interest at the Long Term Rate.

The Issuer

The Issuer is a public body corporate and politic duly created and existing as a county and political subdivision under the Constitution and laws of the Commonwealth of Kentucky. The Issuer is authorized by Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (collectively, the "Act") to (a) issue the Bonds to pay and discharge the 2007 Bonds, (b) lend the proceeds from the sale of the Bonds to the Company for such purpose and (c) enter into and perform its obligations under the Loan Agreement and the Indenture. The Issuer, through its legislative body, the Fiscal Court, has adopted one or more ordinances authorizing the issuance of the Bonds and the execution and delivery of the related documents.

THE BONDS WILL BE 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, INCLUDING AMOUNTS PAYABLE ON THE FIRST MORTGAGE BONDS. THE BONDS WILL NOT CONSTITUTE AN INDEBTEDNESS, GENERAL OBLIGATION OR PLEDGE OF THE FAITH AND CREDIT OR TAXING POWER OF THE ISSUER, THE COMMONWEALTH OF KENTUCKY OR ANY POLITICAL SUBDIVISION THEREOF, AND WILL NOT GIVE RISE TO A PECUNIARY LIABILITY OF THE ISSUER OR A CHARGE AGAINST ITS GENERAL CREDIT OR TAXING POWERS.

The Project

The Project being refinanced with the Bonds has been completed and is the property of the Company, subject to the lien of the First Mortgage Indenture. The Project consists of certain solid waste disposal facilities at the Company's Ghent Generating Station located in Carroll County, Kentucky (the "Generating Station"), for the collection, storage, treatment and final disposal of solid wastes.

Use of Proceeds

The proceeds from the sale of the Bonds (other than any accrued interest) will be used, together with funds to be provided by the Company, to pay and discharge at a redemption price of 100% of the principal amount thereof, plus accrued interest, all of the outstanding 2007 Bonds, on the date of the issuance of the Bonds. The 2007 Bonds currently bear interest at a rate of 5.75% per annum and mature on February 1, 2026.

Summary of the Bonds

General

The Bonds will be issued in the aggregate principal amount set forth on the cover page of this Official Statement. The Bonds will mature as to principal on February 1, 2026. The Bonds are also subject to redemption prior to maturity as described in this Official Statement.

The Bonds will bear interest at the Long Term Rate of 3.375% per annum commencing September 5, 2018. Interest on the Bonds will be paid on each June 1 and December 1, commencing December 1, 2018. The Bonds will continue to bear interest at such Long Term Rate until a Conversion to another Interest Rate Mode or until the maturity or redemption of the Bonds. The permitted Interest Rate Modes for the Bonds are (i) the Flexible Rate, (ii) the Daily Rate, (iii) the Weekly Rate, (iv) the Semi Annual Rate, (v) the Annual Rate, (vi) the Long Term Rate and (vii) the SIFMA-Based Term Rate.

This Official Statement only describes the terms and provisions applicable to the Bonds while accruing interest at such Long Term Rate.

Interest on the Bonds will be computed on the basis of a 360-day year, consisting of twelve 30-day months. Interest payable on each June 1 and December 1 will be payable to the registered owner of the Bond as of the May 15 and November 15 preceding such June 1 and December 1.

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 Official Statement. See "— Book-Entry-Only System" below. Individual purchases of book-entry interests in the Bonds will be made in book-entry-only form in denominations of $5,000 and multiples thereof.

So long as the Bonds are held in book-entry-only form, the principal or redemption price of and interest on, and purchase price of, the Bonds will be payable by the Trustee, as paying agent (the "Paying Agent"), through the facilities of DTC (or a successor depository).

Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the designated office of the Trustee, as bond registrar (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) which has been purchased (see "Mandatory Purchase of Bonds — 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.

Certain Definitions

As used herein, each of the following terms will have the meaning indicated.

"*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 herein) or the registered holder of such Bond if such Bond is not then registered in the name of Cede & Co.

"*Business Day*" means any day other than (i) a Saturday or Sunday or legal holiday or a day on which banking institutions in the city in which the designated 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 or (ii) a day on which the New York Stock Exchange is closed.

"*Conversion*" means any conversion from time to time in accordance with the terms of the Indenture of the Bonds from one Interest Rate Mode to another Interest Rate Mode or the establishment of a new Long Term Rate Period. The Bonds will be subject to Conversion on or after December 1, 2023.

"*Interest Rate Mode*" means the Flexible Rate, the Daily Rate, the Weekly Rate, the Semi-Annual Rate, the Annual Rate, the Long Term Rate and the SIFMA-Based Term Rate.

"*Long Term Rate Period*" means the period beginning on, and including, the date of issuance of the Bonds and ending on, and including, the day immediately 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.

"*Remarketing Agent*" means any remarketing agent selected from time to time by the Company to act, if necessary, as the Remarketing Agent with respect to the Bonds. Any Remarketing Agent will be appointed in accordance with the terms of the Indenture and a remarketing agreement to be entered into between such Remarketing Agent and the Company (the "Remarketing Agreement"). The Remarketing Agent may, without notice to the Company, assign its rights and obligations as Remarketing Agent to a broker-dealer affiliate in accordance with the terms of the Indenture and the Remarketing Agreement.

"*Tender Agent*" means, so long as the Bonds are held in DTC's book-entry-only system, the Trustee, who will act as Tender Agent under the Indenture. Any successor Tender Agent appointed pursuant to the Indenture will also be a Paying Agent.

Redemptions

Optional Redemption. The Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, on any date on or after December 1, 2023 at a redemption price of 100% of the principal amount thereof plus interest accrued, if any, to the redemption date.

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 occur within 180 days preceding the giving of written notice by the Company to the Trustee of such election:

(i) 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 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;

(ii) 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;

(iii) 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

(iv) 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 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.

As a result of a Company Letter Agreement between the Issuer and the Company, to be dated as of September 5, 2018, the Company will agree that it will not, prior to 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, exercise the rights under the Loan Agreement it would otherwise have to redeem the Bonds under the following circumstances:

(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; or

(ii) if 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 have occurred, which, in the judgment of the Company, render the continued operation of the Generating Station or any generating unit at the Generating Station uneconomical; or changes in circumstances after the issuance of the Bonds, including but not limited to changes in solid waste disposal requirements, have occurred such that the Company determines that use of the Project is no longer required or desirable.

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 compliance with the terms of the First Mortgage Indenture and 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."

Mandatory Redemption; Determination of Taxability. The Bonds are required to be redeemed by the Issuer, in whole, or in such part as described below, at a redemption price equal to 100% of the principal amount thereof, without redemption premium, plus accrued interest, if any, to the redemption date, within 180 days following a "Determination of Taxability." As used herein, a "Determination of Taxability" means the receipt by the Trustee of written notice from a current or former registered owner of a Bond or from the Company or the Issuer of (i) the issuance of a published or private ruling or a technical advice memorandum by the Internal Revenue Service in which the Company participated or has been given the opportunity to participate, and which ruling or memorandum the Company, in its discretion, does not contest or from which no further right of administrative or judicial review or appeal exists, or (ii) a final determination from which no further right of appeal exists of any court of competent jurisdiction in the United States in a proceeding in which the Company has participated or has been a party, or has been given the opportunity to participate or be a party, in each case, to the effect that as a result of a failure by the Company to perform or observe any covenant or agreement or the inaccuracy of any representation contained in the Loan Agreement or any other agreement or certificate delivered in connection with the Bonds, the interest on the Bonds is included in the gross income of the owners thereof for federal income tax purposes, other than with respect to a person who is a "substantial user" or a "related person" of a substantial user of the Project within the meaning of Section 147 of the 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 will exhaust or choose not to exhaust all available proceedings for the contest, review, appeal or rehearing of such decree, judgment or action which the Company determines to be appropriate. No Determination of Taxability described above will result from the inclusion of interest on any Bond in the computation of minimum or indirect taxes. All of the Bonds are required to be redeemed upon a Determination of Taxability as described above unless, in the opinion of Bond Counsel, redemption of a portion of such Bonds would have the result that interest payable on the remaining Bonds outstanding after the redemption would not be so included in any such gross income.

In the event any of the Issuer, the Company or the Trustee has been put on notice or becomes aware of the existence or pendency of any inquiry, audit or other proceedings relating to the Bonds being conducted by the Internal Revenue Service, the party so put on notice is required to give immediate written notice to the other parties of such matters. Promptly upon learning of the occurrence of a Determination of Taxability (whether or not the same is being contested), or any of the events described above, the Company is required to give notice thereof to the Trustee and the Issuer.

If the Internal Revenue Service or a court of competent jurisdiction determines that the interest paid or to be paid on any Bond (except to a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) is or was includable in the gross income of the recipient for federal income tax purposes for reasons other than as a result of a failure by the Company to perform or observe any of its covenants, agreements or representations in the Loan Agreement or any other agreement or certificate delivered in connection therewith, the Bonds are not subject to redemption. In such circumstances, Bondholders would continue to hold their Bonds, receiving principal and interest at the applicable rate as and when due, but would be required to include such interest payments in gross income for federal income tax purposes. Also, if the lien of the Indenture is discharged or defeased prior to the occurrence of a final Determination of Taxability, Bonds will not be redeemed as described herein.

General Redemption Terms. 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 20 days prior to the redemption date.

Any notice mailed as provided in the Indenture will be conclusively presumed to have been given, irrespective of whether the owner receives the notice. Failure to give any such notice by mailing or any defect therein in respect of any Bond will not affect the validity of any proceedings for the redemption of any other Bond. No further interest will accrue on the principal of any Bond called for redemption after the redemption date if funds sufficient for such redemption have been deposited with the Paying Agent as of the redemption date. If the provisions for discharging the Indenture set forth below under the heading "Summary of the Indenture — Discharge of Indenture" have not been complied with, any redemption notice may state that it is conditional on there being sufficient moneys to pay the full redemption price for the Bonds to be redeemed and that if sufficient funds have not been received by the Trustee by the opening of business on the redemption date, such notice shall be of no effect. So long as the Bonds are held in book-entry-only form, all redemption notices will be sent only to Cede & Co.

Conversion of Interest Rate Modes

The Interest Rate Mode for the Bonds is subject to Conversion from time to time on or after December 1, 2023 at the option of the Company in accordance with the terms of the Indenture, upon notice from the Bond Registrar to the registered owners of the Bonds. Upon Conversion, the Bonds will be subject to mandatory purchase 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.

Mandatory Purchase of Bonds

General. The Bonds will be subject to mandatory purchase on Conversion at a purchase price equal to the principal amount thereof plus accrued and unpaid interest. Notice to owners of such mandatory purchase will be given by the Bond Registrar by first class mail at least 20 days prior to the purchase date. The notice of mandatory purchase will state those matters required to be set forth therein under the Indenture.

Remarketing and Purchase of Bonds. The Indenture provides that, subject to the terms of a Remarketing Agreement with the Company, unless otherwise instructed by the Company, the Remarketing Agent will use its commercially reasonable best efforts to remarket Bonds purchased. 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. Payment of the purchase price of any Bond will be payable on the purchase date upon delivery of such Bond to the Tender Agent on such date; provided that such Bond must be delivered to the Tender Agent at or prior to 11:00 a.m. (New York City time). 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. If the purchase date 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 such 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 such purchase date. 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.

Security

Payment of the principal or redemption price of and interest on the Bonds will be secured by an assignment by the Issuer to the Trustee of the Issuer's interest in and to the Loan Agreement and all payments to be made pursuant thereto (other than certain indemnification and expense payments). Pursuant to the Loan Agreement, the Company will agree to pay, among other things, amounts sufficient to pay the aggregate principal amount or redemption price of 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 or redemption price of and interest on the Bonds will be further secured by the First Mortgage Bonds. The principal amount of the First Mortgage Bonds will equal the principal amount of the Bonds. If the Bonds become immediately due and payable as a result of a default in payment of the principal or redemption price of 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 ("Redemption Demand"), or if all first mortgage bonds outstanding under the First Mortgage

Indenture shall have become immediately due and payable, such First Mortgage Bonds will begin to 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 and the First Mortgage Indenture."

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.

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 Underwriter 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) or such other name as may be requested by an authorized representative of DTC. One fully registered bond in the aggregate principal amount of the Bonds will be deposited with DTC.

DTC 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 U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments 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. DTCC 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, however, are 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 and 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 only system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of Bonds with DTC and their registration in the name of Cede & Co. or such other nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Redemption notices shall be sent to DTC. If fewer 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.

The requirement for physical delivery of Bonds in connection with 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 delivered as described in the Indenture (see "— Revision of Book-Entry-Only System; Replacement Bonds" below). The Beneficial Owner, upon registration of certificates held in the Beneficial Owner's name, will become the registered owner of the Bonds.

So long as Cede & Co. is the registered owner of the Bonds, as nominee of DTC, references herein to the registered owners of the Bonds will mean Cede & Co. and will not mean the Beneficial Owners. Under the Indenture, payments made by the Trustee to DTC or its nominee will satisfy the Issuer's obligations under the Indenture 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 and the Underwriter 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 Official Statement.

THE ISSUER, THE COMPANY, THE UNDERWRITER AND THE TRUSTEE WILL HAVE NO RESPONSIBILITY OR OBLIGATION TO ANY DIRECT PARTICIPANT, INDIRECT PARTICIPANT OR ANY BENEFICIAL OWNER OR ANY OTHER PERSON NOT SHOWN ON THE REGISTRATION BOOKS OF THE TRUSTEE AS BEING A REGISTERED OWNER WITH RESPECT TO: (1) THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC OR ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT; (2) THE PAYMENT OF ANY AMOUNT DUE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER IN RESPECT OF THE PRINCIPAL AMOUNT OR REDEMPTION OR PURCHASE PRICE OF OR INTEREST ON THE BONDS; (3) THE DELIVERY OF ANY NOTICE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER WHICH IS REQUIRED OR PERMITTED TO BE GIVEN TO REGISTERED OWNERS UNDER THE TERMS OF THE INDENTURE; (4) THE SELECTION OF THE BENEFICIAL OWNERS TO RECEIVE PAYMENT IN THE EVENT OF ANY PARTIAL REDEMPTION OF THE BONDS; OR (5) ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC AS REGISTERED OWNER.

Revision of Book-Entry-Only System; Replacement Bonds

In the event that DTC determines not to continue as securities depository or is removed by the Issuer, at the direction of the Company, as securities depository, the Issuer, at the direction of the Company, may appoint a successor securities depository reasonably acceptable to the Trustee. If the Issuer does not or is unable to appoint a successor securities depository, the Issuer will issue and the

Trustee will authenticate and deliver fully registered Bonds, in authorized denominations, to the assignees of DTC or their nominees.

In the event that the book-entry-only system is discontinued, the following provisions will apply. The Bonds may be issued in denominations of $5,000 and multiples thereof. Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the designated 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 mandatory purchase as described under "Mandatory Purchase 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 Official Statement, 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 term of the Loan Agreement will commence as of its date and end on the earliest to occur of February 1, 2026 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 will agree to repay the loan pursuant to the Loan Agreement by making timely payments to the Trustee in sufficient amounts to pay the principal or redemption price of and interest required to be paid on the Bonds on each date upon which any such payments are due. The Company will also agree 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 will covenant and agree 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 — Mandatory Purchase of 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) will be assigned by the Issuer to the Trustee, and the Company will pay such amounts directly to the Trustee. The obligations of the Company to make the payments pursuant to the Loan Agreement are absolute and unconditional.

Maintenance of Tax Exemption

The Company and the Issuer will agree 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 will execute and deliver to the Trustee the First Mortgage Bonds on the date of issuance of the Bonds. The principal amount of the First Mortgage Bonds executed and delivered to the Trustee will equal 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 or redemption price of 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 Redemption Demand, or if all first mortgage bonds outstanding under the First Mortgage Indenture shall have become immediately due and payable, such First Mortgage Bonds will then 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 or redemption price of and interest on any of the Bonds, and the surrender to and cancellation thereof by the Trustee, or upon provision for the payment thereof having been made in accordance with the Indenture, First Mortgage Bonds with corresponding principal amounts equal to the aggregate principal amount of the Bonds so surrendered and canceled or for the payment of which provision has been made, will be surrendered by the Trustee to the First Mortgage Trustee and will be canceled by the First Mortgage Trustee. The First Mortgage Bonds will be registered in the name of the Trustee and will be non transferable, except to effect transfers to any successor trustee under the Indenture.

Payment of Taxes

The Company will agree 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 the heading "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, preserve and keep the Project or cause the Project to be maintained, preserved and kept in good repair, working order and condition and will make or cause to be made all proper repairs, replacements and renewals necessary to continue to constitute the Project as "pollution control facilities" as defined in Section 103.246(1)(a) of the Act. However, the Company will have no obligation to maintain, preserve, keep, repair, replace or renew any portion of the Project, the maintenance, preservation, keeping, 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 are 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 as "pollution control facilities" as defined in Section 103.246(1)(a) of 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 must, subject to the requirements of the First Mortgage Indenture, (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, by the opinion of Bond Counsel, will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes. See "Summary of the Bonds — Redemptions — Extraordinary Optional Redemption in Whole or in Part."

Project Insurance

The Company will insure the Project in 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 entity, provided the acquirer of the Company's assets or the entity with which it will consolidate with or merge into is a corporation or other business organization organized and existing under the laws of the United States of America or one of the states of the United States of America or the District of Columbia, is qualified and admitted to do business in the Commonwealths of Kentucky and Virginia, assumes in writing all of the obligations and covenants of the Company under the Loan Agreement and delivers a copy of such assumption to the Issuer and the 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 therein taking into account any periods of grace provided in the Indenture and the Bonds for the applicable payment of interest on the Bonds (see "Summary of the Indenture — Defaults and Remedies"), and such failure shall cause an event of default under the Indenture;

(ii) failure by the Company to observe and perform any covenant, condition or agreement on its part to be observed or performed, other than as referred to in paragraph (i) above, for a period of 30 days after written notice by the Issuer or Trustee, subject to extension by the Issuer and the Trustee, provided, however, that if such failure is capable of being corrected, but cannot be corrected in such 30-day period, the Issuer and the Trustee will not unreasonably withhold their consent to an extension of such time if corrective action with respect thereto is instituted within such period and is being diligently pursued;

(iii) certain events of bankruptcy, dissolution, liquidation, reorganization or insolvency of the Company;

(iv) the occurrence of an Event of Default under the Indenture; 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.

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 execute and deliver the First Mortgage Bonds to the Trustee on or before the date of issuance of the Bonds in an amount equal to the principal amount of the Bonds; (iii) 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 entity unless certain provisions of the Loan Agreement are satisfied; and (iv) 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 and continuance of an Event of Default under the Loan Agreement, the Trustee, on behalf of the Issuer, may, among other things, take whatever action at law or in equity may appear necessary or desirable to collect the amounts then due and thereafter to become due, or to enforce performance and observance of any obligation, agreement or covenant of the Company, under the Loan Agreement, including any remedies available in respect of the First Mortgage Bonds.

In the event of a default in payment of the principal or redemption price of or interest on the Bonds and the acceleration of the maturity date of the Bonds (to the extent not already due and payable) as a consequence of such Event of Default, the Trustee may demand redemption of the First Mortgage Bonds. See "Summary of the First Mortgage Bonds and the First Mortgage Indenture" and "Summary of the Indenture — Defaults and Remedies." Any amounts collected upon the happening of any such Event of Default must be applied in accordance with the Indenture or, if the Bonds have been fully paid (or provision for payment thereof has been made in accordance with the Indenture) and all other liabilities of the Company accrued under the Indenture and the Loan Agreement have been paid or satisfied, made available to the Company.

Options to Prepay; Obligation to Prepay

The Company may prepay the loan pursuant to the Loan Agreement, in whole or in part, on certain dates, at the prepayment prices as shown under the headings "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 heading "Summary of the Bonds — Redemptions — Mandatory Redemption; Determination of Taxability," the Company will be obligated to prepay the loan in an aggregate amount sufficient to redeem the required principal amount of the Bonds.

In each instance, the loan prepayment price must be a sum sufficient, together with other funds deposited with the Trustee and available for such purpose, to redeem the requisite amount of the Bonds at a price equal to 100% of the principal amount plus accrued interest to the redemption date, and to pay all reasonable and necessary fees and expenses of the Trustee, the Paying Agent, the Bond Registrar and the Tender Agent and all other liabilities of the Company under the Loan Agreement accrued to the redemption date.

Amendments and Modifications

No alteration, amendment, change, supplement 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 alteration, amendment, change, supplement 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 alterations, amendments, changes, supplements or modifications, the Loan Agreement may be altered, amended, changed, supplemented 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 alteration, amendment, change, supplement or modification with respect to the Loan Agreement of the type described in clauses (i) through (iv) of the first sentence of the third paragraph of "Summary of the Indenture — Supplemental Indentures."

Summary of the First Mortgage Bonds and the First Mortgage Indenture

The following, in addition to the provisions contained elsewhere in this Official Statement, is a brief description of certain provisions of the First Mortgage Bonds and the First Mortgage Indenture. This description is only a summary and does not purport to be complete and definitive. Reference is made to the First Mortgage Indenture and to the form of the First Mortgage Bonds for the detailed provisions thereof.

General

In connection with the issuance of the Bonds, the First Mortgage Bonds will be issued in a principal amount equal to the principal amount of the Bonds and will constitute a new series of first mortgage bonds under the First Mortgage Indenture (see "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds"). The statements herein made (being for the most part summaries of certain provisions of the First Mortgage Indenture) are subject to the detailed provisions of the First

Mortgage Indenture, which is incorporated herein by this reference. Words or phrases italicized are defined in the First Mortgage Indenture.

The First Mortgage Bonds will mature on the same date and bear interest at the same rate or rates as the Bonds; however, the principal of and interest on the First Mortgage Bonds will not be payable other than upon the occurrence of an event of default under the Loan Agreement. If the Bonds become immediately due and payable as a result of a default in payment of the principal or redemption price of or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement, and if all first mortgage bonds outstanding under the First Mortgage Indenture shall not have become immediately due and payable following an *event of default* under the First Mortgage Indenture, the Company will be obligated to redeem the First Mortgage Bonds upon receipt by the First Mortgage Trustee of a Redemption Demand from the Trustee for redemption, at a redemption price equal to the principal amount thereof plus accrued interest at the rates borne by the Bonds from the last date to which interest on the Bonds has been paid.

The First Mortgage Bonds at all times will be in fully registered form registered in the name of the Trustee, will be non negotiable, and will be non transferable except to any successor trustee under the Indenture. Upon payment and cancellation of Bonds by the Trustee or the Paying Agent (other than any Bond or portion thereof that was canceled by the Trustee or the Paying Agent and for which one or more Bonds were delivered and authenticated pursuant to the Indenture), whether at maturity, by redemption or otherwise, or upon provision for the payment of the Bonds having been made in accordance with the Indenture, an equal principal amount of First Mortgage Bonds will be deemed fully paid and the obligations of the Company thereunder will cease.

Security; Lien of the First Mortgage Indenture

General. Except as described below under this heading and under "— Issuance of Additional First Mortgage Bonds," and subject to the exceptions described under "— Satisfaction and Discharge," all first mortgage bonds issued under the First Mortgage Indenture, including the First Mortgage Bonds, will be secured, equally and ratably, by the lien of the First Mortgage Indenture, which constitutes, subject to permitted liens and exclusions as described below, a first mortgage lien on substantially all of the Company's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity (other than property duly released from the lien of the First Mortgage Indenture in accordance with the provisions thereof and other than excepted property, as described below). Property that is subject to the lien of the First Mortgage Indenture is referred to below as "Mortgaged Property."

The Company may obtain the release of property from the lien of the First Mortgage Indenture from time to time, upon the bases provided for such release in the First Mortgage Indenture. See "— Release of Property."

The Company may enter into supplemental indentures with the First Mortgage Trustee, without the consent of the holders of the first mortgage bonds, in order to subject additional property (including property that would otherwise be excepted from such lien) to the lien of the First Mortgage Indenture. This property would constitute *property additions* and would be available as a basis for the issuance of additional first mortgage bonds. See "— Issuance of Additional First Mortgage Bonds."

The First Mortgage Indenture provides that after-acquired property (other than *excepted property*) will be subject to the lien of the First Mortgage Indenture. However, in the case of consolidation or merger (whether or not the Company is the surviving company) or transfer of the Mortgaged Property as or substantially as an entirety, the First Mortgage Indenture will not be required to be a lien upon any of the properties either owned or subsequently acquired by the successor company except properties acquired from the Company in or as a result of such transfer, as well as improvements, extensions and additions (as defined in the First Mortgage Indenture) to such properties and renewals, replacements and substitutions of or for any part or parts thereof. See "— Consolidation, Merger and Conveyance of Assets as an Entirety."

Excepted Property. The lien of the First Mortgage Indenture does not cover, among other things, the following types of property: property located outside of Kentucky and not specifically subjected or required to be subjected to the lien of the First Mortgage Indenture; property not used by the Company in its electric generation, transmission and distribution business; cash and securities not paid, deposited or held under the First Mortgage Indenture or required so to be; contracts, leases and other agreements of all kinds, contract rights, bills, notes and other instruments, revenues, accounts receivable, claims, demands and judgments; governmental and other licenses, permits, franchises, consents and allowances; intellectual property rights and other general intangibles; vehicles, movable equipment, aircraft and vessels; all goods, stock in trade, wares, merchandise and inventory held for the purpose of sale or lease in the ordinary course of business; materials, supplies, inventory and other personal property consumable in the operation of the Company's business; fuel; tools and equipment; furniture and furnishings; computers and data processing, telecommunications and other facilities used primarily for administrative or clerical purposes or otherwise not used in connection with the operation or maintenance of electric generation, transmission and distribution facilities; coal, ore, gas, oil and other minerals and timber rights; electric energy and capacity, gas, steam, water and other products generated, produced, manufactured, purchased or otherwise acquired; real property and facilities used primarily for the production or gathering of natural gas; property which has been released from the lien of the First Mortgage Indenture; and leasehold interests. Property of the Company not covered by the lien of the First Mortgage Indenture is referred to herein as excepted property. Properties held by any of the Company's subsidiaries, as well as properties leased from others, would not be subject to the lien of the First Mortgage Indenture.

Permitted Liens. The lien of the First Mortgage Indenture is subject to permitted liens described in the First Mortgage Indenture. Such *permitted liens* include liens existing at the execution date of the First Mortgage Indenture, purchase money liens and other liens placed or otherwise existing on property acquired by the Company after the execution date of the First Mortgage Indenture at the time the Company acquires it, tax liens and other governmental charges which are not delinquent or which are being contested in good faith, mechanics', construction and materialmen's liens, certain judgment liens, easements, reservations and rights of others (including governmental entities) in, and defects of title to, the Company's property, certain leases and leasehold interests, liens to secure public obligations, rights of others to take minerals, timber, electric energy or capacity, gas, water, steam or other products produced by the Company or by others on the Company's property, rights and interests of persons other than the Company arising out of agreements relating to the common ownership or joint use of property, and liens on the interests of such persons in such property and liens which have been bonded or for which other security arrangements have been made.

The First Mortgage Indenture also provides that the First Mortgage Trustee will have a lien, prior to the lien on behalf of the holders of the first mortgage bonds, including the First Mortgage Bonds, upon the Mortgaged Property as security for the Company's payment of its reasonable compensation and expenses and for indemnity against certain liabilities. Any such lien would be a *permitted lien* under the First Mortgage Indenture.

Issuance of Additional First Mortgage Bonds

The maximum principal amount of first mortgage bonds that may be authenticated and delivered under the First Mortgage Indenture is subject to the issuance restrictions described below; provided, however, that the maximum principal amount of first mortgage bonds outstanding at any one time shall not exceed One Quintillion Dollars ($1,000,000,000,000,000,000), which amount may be changed by supplemental indenture. As of June 30, 2018, first mortgage bonds in an aggregate principal amount of $2,341,852,405 were outstanding under the First Mortgage Indenture, of which $341,852,405 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 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 in accordance with U.S. generally accepted accounting principles.

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.

At June 30, 2018, approximately $2.2 billion of *property additions* and $258.9 million of *retired securities* were available to be used as the basis for the authentication and delivery of first mortgage bonds. The Company intends to issue the First Mortgage Bonds on the basis of *retired securities*.

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 that is 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; and
    - 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 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 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; and

- in the case of a lease, such lease is made expressly subject to termination by (i) the Company or by the First Mortgage Trustee and (ii) the purchaser of the property so leased at any sale thereof, at any time during the continuance of an *event of default*; and

- immediately after giving effect to such transaction, no *event of default*, and no event which after notice or lapse of time or both would become an *event of default*, will have occurred and be continuing.

In the case of the conveyance or other transfer of the Mortgaged Property as or substantially as an entirety to any other person, upon the satisfaction of all the conditions described above the Company would be released and discharged from all obligations under the First Mortgage Indenture and on the first mortgage bonds then outstanding unless the Company elects to waive such release and discharge.

The First Mortgage Indenture does not prevent or restrict:

- any consolidation or merger after the consummation of which the Company would be the surviving or resulting entity; or

- any conveyance or other transfer, or lease, of any part of the Mortgaged Property which does not constitute the entirety or substantially the entirety thereof.

If following a conveyance or other transfer, or lease, of any part of the Mortgaged Property, the fair value of the Mortgaged Property retained by the Company exceeds an amount equal to three-halves (3/2) of the aggregate principal amount of all outstanding first mortgage bonds, then the part of the Mortgaged Property so conveyed, transferred or leased shall be deemed not to constitute the entirety or substantially the entirety of the Mortgaged Property. This *fair value* will be determined within 90 days of the conveyance or transfer by an independent expert that the Company selects and that is approved by the First Mortgage Trustee.

Modification of First Mortgage Indenture

Without Holder Consent. Without the consent of any holders of first mortgage bonds, the Company and the First Mortgage Trustee may enter into one or more supplemental indentures for any of the following purposes:

- to evidence the succession of another entity to the Company;
- to add one or more covenants or other provisions for the benefit of the holders of all or any series or tranche of first mortgage bonds, or to surrender any right or power conferred upon the Company;
- to correct or amplify the description of any property at any time subject to the lien of the First Mortgage Indenture; or to better assure, convey and confirm unto the First Mortgage Trustee any property subject or required to be subjected to the lien of the First Mortgage Indenture; or to subject to the lien of the First Mortgage Indenture additional property (including property of others), to specify any additional Permitted Liens with respect to such additional property and to modify the provisions in the First Mortgage Indenture for dispositions of certain types of property without release in order to specify any additional items with respect to such additional property;
- to add any additional *events 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 the 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 Official Statement, 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 will assign and pledge 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 to be 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 application of the amounts assigned to payment of the principal or redemption price of and interest on the Bonds.

The Bond Fund

The payments to be made by the Company pursuant to the Loan Agreement to the Issuer and certain other amounts specified in the Indenture will be deposited into a Bond Fund established pursuant to the Indenture (the "Bond Fund") and will be maintained in trust by the Trustee. Moneys in the Bond Fund will be used solely and only for the payment of the principal or redemption price of and interest on the Bonds, and for the payment of the reasonable fees and expenses to which the Trustee, Bond Registrar, Tender Agent, Authenticating Agent, any Paying Agent and the Issuer are entitled pursuant to the Indenture or the Loan Agreement. Any moneys held in the Bond Fund will be invested by the Trustee at the specific written direction of the Company in certain Governmental Obligations, investment-grade corporate obligations and other investments permitted under the Indenture.

The 2007 Bond Fund

The proceeds from the issuance of the Bonds will be deposited by the Trustee in the County of Carroll, Kentucky, Environmental Facilities Revenue Bond Fund, 2007 Series A (Kentucky Utilities Company Project) created by the Indenture of Trust dated as of March 1, 2007 for the 2007 Bonds in an amount adequate to pay, together with other moneys to be provided by the Company, all principal of and accrued interest on the 2007 Bonds to become due and payable on their scheduled redemption date.

The Rebate Fund

A Rebate Fund has been created by the Indenture (the "Rebate Fund") and will be maintained as a separate fund free and clear of the lien of the Indenture. The Issuer, the Trustee and the Company have agreed to comply with all rebate requirements of the Code and, in particular, the Company has agreed that if necessary, it will deposit in the Rebate Fund any such amount as is required under the Code. However, the Issuer, the Trustee and the Company may disregard the Rebate Fund provisions to the extent that they receive an opinion of Bond Counsel that such failure to comply will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes.

Discharge of Indenture

When all the Bonds and all fees and charges accrued and to accrue of the Trustee and the Paying Agent have been paid or provided for, and when proper notice has been given to the Bondholders or the Trustee that the proper amounts have been so paid or provided for, and if the Issuer is not in default in any other respect under the Indenture, the Indenture will become null and void. The Bonds will be deemed to have been paid and discharged when there have been irrevocably deposited with the Trustee moneys sufficient to pay the principal or redemption price of and accrued interest on such Bonds to the due date (whether such date be by reason of maturity or upon redemption) or, in lieu thereof, Governmental Obligations have been deposited which mature in such amounts and at such times as will provide the funds necessary to so pay such Bonds, and when all reasonable and necessary fees and expenses of the Trustee, the Tender Agent, the Authenticating Agent, the Bond Registrar and the Paying Agent have been paid or provided for.

Surrender of First Mortgage Bonds

Upon payment of any principal or redemption price of 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 due and punctual payment of any installment of interest on any Bond within a period of five Business Days from the due date;

(ii) failure to make due and 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 at the opening of business on the next Business Day as described in the last paragraph under "Summary of the Bonds — Mandatory Purchase of Bonds — Remarketing and Purchase of Bonds" above;

(iii) failure by 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 or by the registered owners holding not less than 25% in aggregate principal amount of all Bonds outstanding, 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, must: (i) enforce each and every right granted to the Trustee as a holder of the First Mortgage Bonds (see "Summary of the First Mortgage Bonds and the First Mortgage Indenture"), (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. Interest on the Bonds will cease to accrue on the date of issuance of a declaration of acceleration of payment of the principal and interest on the Bonds.

In exercising such rights, the Trustee will take any action that, in the judgment of the Trustee, would best serve the interests of the registered owners, taking into account the security and remedies afforded to holders of first mortgage bonds under the First Mortgage Indenture. 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 or redemption price of and interest on the Bonds then outstanding.

If an Event of Default under the Indenture shall occur and be continuing and the maturity date of the Bonds has been accelerated (to the extent the Bonds are not already due and payable) as a consequence of such event of default, the Trustee may, and upon the written request of the registered owners holding not less than 25% in principal amount of all Bonds then outstanding and upon receipt of indemnity satisfactory to it shall, exercise such rights as it shall possess under the First Mortgage Indenture as a holder of the First Mortgage Bonds and shall also issue a Redemption Demand for such First Mortgage Bonds to the First Mortgage Trustee.

If the Trustee recovers any moneys following an Event of Default, unless the principal of the Bonds 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.

Waiver of Events of Default

Except as provided below, the Trustee may in its discretion waive any Event of Default under the Indenture and will do so upon the written request of the registered owners holding a majority in principal amount of all Bonds then outstanding. If, after the principal of all Bonds then outstanding have been declared to be due and payable as a result of a default under the Indenture and prior to any judgment or decree for the appointment of a receiver or for the payment of the moneys due has been obtained or entered, (i) the Company causes to be deposited with the Trustee a sum sufficient to pay all matured installments of interest upon all Bonds and the principal of and premium, if any, on any and all Bonds which would become due otherwise than by reason of such declaration (with interest thereon as provided in the Indenture) and the expenses of the Trustee in connection with such default and (ii) all Events of Default under the Indenture (other than nonpayment of the principal of Bonds due by 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 subheading "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 or redemption price of and interest on the Bonds after the maturity thereof.

Voting of First Mortgage Bonds Held by Trustee

The Indenture provides that the Trustee, as the holder of the First Mortgage Bonds, will be required to attend such meeting or meetings of bondholders under the First Mortgage Indenture or, at its option, deliver its proxy in connection therewith, as relate to matters with respect to which it, as such holder, is entitled to vote or consent. The Trustee, either at any such meeting or meetings or otherwise when the consent of the holders of the First Mortgage Bonds is sought without a meeting, will be required to vote all First Mortgage Bonds then held by it, or consent with respect thereto, proportionately with the vote or consent of the holders of all other securities of the Company then outstanding under the First Mortgage Indenture eligible to vote or consent, as evidenced by, and as to be delivered to the Trustee, a certificate signed by the temporary chairman, the temporary secretary, the permanent chairman, the permanent secretary, or an inspector of votes at any meeting or meetings of security holders under the First Mortgage Indenture, or by the First Mortgage Trustee in the case of consents of such security holders which are sought without a meeting, which states what the signer thereof reasonably believes are the proportionate votes or consents of the holders of all securities (other than the First Mortgage Bonds) outstanding under the First Mortgage Indenture and counted for the purposes of determining whether such security holders have approved or consented to the matter put before them; provided, however, that the Trustee shall not so vote in favor of, or so consent to, any amendment or modification of the First Mortgage Indenture, which, if it were an amendment or modification of the Indenture, would require the consent of the Bondholders as described in the third paragraph under the heading "Summary of the Indenture – Supplemental Indenture," without the prior consent and approval of Bondholders which would be so required; provided further that as a condition to the Trustee voting or giving such consent, the Trustee shall have received a certificate of a Company representative or an opinion of counsel, at its election, stating that such voting or consent is authorized or permitted by the Indenture.

Supplemental Indentures

The Issuer and the Trustee may enter into indentures supplemental to the Indenture as shall not be inconsistent with the terms and provisions of 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 (v) 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, including any modifications necessary to upgrade or maintain the then applicable ratings on the Bonds or (ix) to permit the issuance of the Bonds in other than book-entry-only form or to provide changes to or for the book-entry system.

Notwithstanding the foregoing, the Company, with the consent of the Trustee, may at any time further secure the Bonds by means of a letter of credit, other credit facility or other guarantee or collateral.

Exclusive of supplemental indentures for the purposes set forth in the preceding two paragraphs, 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 designated office of the Trustee for inspection. If, within sixty days (or such longer period as prescribed by the Issuer or the Company) following the giving of such notice, the registered owners holding the requisite amount of the Bonds outstanding have consented to the execution thereof, no Bondholder will have any right to object or question the execution thereof.

No supplemental indenture will become effective unless the Company consents to the execution and delivery of such supplemental indenture. The Company will be deemed to have consented to the execution and delivery of any supplemental indenture if the Trustee does not receive a notice of protest or objection signed by the Company on or before 4:30 p.m., local time in the city in which the designated 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 and 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.

Tax Treatment

In the opinion of Bond Counsel, under existing law, including current statutes, regulations, administrative rulings and official interpretations, subject to the qualifications and exceptions set forth below, interest on the Bonds will be excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion will be expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person" as such terms are used in Section 147(a) of the Code. It is Bond Counsel's further opinion that, subject to the assumptions stated in the preceding sentence, (i) interest on the Bonds will be excluded from gross income of the owners thereof for Kentucky income tax purposes and (ii) the Bonds will be exempt from all ad valorem taxes in Kentucky. Interest on the Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. The alternative minimum tax has been repealed with respect to corporations for taxable years beginning after December 31, 2017.

The opinion of Bond Counsel assumes and is conditioned on the payment and discharge of all of the 2007 Bonds on or before the 90th day following the date of issuance of the Bonds. The Company has agreed (i) to apply all of the proceeds of the bonds to the payment and discharge of the 2007 Bonds within 90 days following the date of issuance of the Bonds, (ii) to provide additional funds necessary, on or prior to a day within 90 days following the date of issuance of the Bonds, to defease and discharge the 2007 Bonds on such day and (iii) to give irrevocable instructions on the date of issuance of the Bonds to the trustee in respect of the 2007 Bonds directing the redemption of the 2007 Bonds.

The opinion of Bond Counsel as to the excludability of interest from gross income for federal income tax purposes will be based upon and will assume the accuracy of certain representations of facts and circumstances, including with respect to the Project, which are 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 will 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, 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 will 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 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.

The Code prescribes 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 will each covenant 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 will be subject to the following exceptions and qualifications:

(i) 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 will express 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 to certain taxpayers, including without limitation, financial institutions, certain insurance companies, individual recipients of Social Security or Railroad Retirement benefits, and taxpayers who may be deemed to have incurred (or continued) indebtedness to purchase or carry tax-exempt obligations. 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.

A draft of the opinion of Bond Counsel relating to the Bonds in substantially the form in which it is expected to be delivered on the date of issuance of the Bonds is attached as Appendix B to this Official Statement.

Legal Matters

Certain legal matters incident to the authorization, issuance and sale by the Issuer of the Bonds are subject to the approving opinion of Bond Counsel. Bond Counsel has in the past, and may in the future, act as counsel to the Company with respect to certain matters. Certain legal matters will be passed upon for the Issuer by its County Attorney. Certain legal matters will be passed upon for the Company by Jones Day, Chicago, Illinois, and John R. Crockett III, General Counsel, Chief Compliance Officer and Corporate Secretary for the Company. Certain legal matters will be passed upon for the Underwriter by its counsel, McGuireWoods LLP, Chicago, Illinois.

Underwriting

"US Bancorp" is the marketing name of U.S. Bancorp and its subsidiaries, including U.S. Bancorp Investments, Inc., which is serving as the underwriter for the Bonds (the "Underwriter"), and U.S. Bank National Association, which is serving as Trustee, Paying Agent, Tender Agent and Registrar for the Bonds.

The Underwriter has agreed, subject to the terms of the bond purchase agreement between the Issuer and the Underwriter, to purchase the Bonds from the Issuer at the public offering price set forth on the cover page of this Official Statement. The Underwriter is committed to purchase all the Bonds if any Bonds are purchased. In connection with the underwriting of the Bonds, the Underwriter will be paid by the Company a fee in the amount of $89,375, which excludes reimbursement for certain reasonable out-of-pocket expenses.

The Underwriter may offer and sell the Bonds to certain dealers and others at prices lower than the public offering price set forth on the cover page of this Official Statement. After the Bonds are released for sale to the public, the public offering price and other selling terms may from time to time be varied by the Underwriter.

In connection with the offering of the Bonds, the Underwriter may over-allot or effect transactions that 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.

Pursuant to an Inducement Letter, the Company has agreed to indemnify the Underwriter and the Issuer against certain civil liabilities, including liabilities under the federal securities laws, or contribute to payments that the Underwriter or the Issuer may be required to make in respect thereof.

In the ordinary course of its business, the Underwriter and certain of its affiliates have in the past and may in the future engage in investment and commercial banking transactions with the Company, including the provision of certain advisory services to the Company.

Continuing Disclosure

Because the Bonds will be 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 Underwriter to comply with the requirements of the Rule, the Company will covenant in a continuing disclosure undertaking agreement to be 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 will covenant 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 Official Statement (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 or 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 shall agree to any amendment so requested by the Company that does not change the duties of the Trustee thereunder) or waive any provision thereof, but only with a change in circumstances that arises from a change in legal requirements, change in law, or change in the nature or status of the Company with respect to the Bonds or the type of business conducted by the Company; provided that the undertaking, as amended or following such waiver, would have complied with the requirements of the Rule on the date of issuance of the Bonds, after taking into account any amendments to the Rule as well as any change in circumstances, and the amendment or waiver does not materially impair the interests of the holders of the Bonds to which such undertaking relates, in the opinion of the Trustee or counsel expert in federal securities laws acceptable to both the Company and the Trustee, or is approved by the Beneficial Owners of a majority in aggregate principal amount of the outstanding Bonds. The Company acknowledges that its undertakings pursuant to the Rule described under this heading are intended to be for the benefit of the holders of the Bonds and shall be enforceable by the holders of those Bonds or by the Trustee on behalf of such holders. Any breach by the Company of these undertakings pursuant to the Rule will not constitute an event of default under the Indenture, the Loan Agreement or the Bonds.

The Company is a party to continuing disclosure agreements with respect to 5 series of pollution control bonds. The MSRB's Electronic Municipal Market Access website reflects that within the past five years the Company did not timely file certain information in connection with December 2014 and June 2016 downgrades of credit ratings for four series of Company pollution control bonds resulting from the downgrade of the bank providing the letters of credit supporting such bonds. Moody's Investors Service, Inc. downgraded the long-term rating of the four Company pollution control bonds on December 2, 2014. The Company was not aware of the downgrade until February 10, 2015 and filed the required disclosures on February 11, 2015. On May 23, 2016, S&P Global Ratings updated its methodology and assumptions for rating jointly supported financial obligations. As a result, S&P Global Ratings downgraded the long-term rating on the four Company pollution control bonds as of June 3, 2016. The Company was not aware of the downgrade until July 24, 2017 and filed the required disclosures on July 24, 2017. The Company has had, and continues to have, procedures in place in order to make material event notices and financial statement filings on an ongoing basis.

This Official Statement has been duly approved, executed and delivered by the County Judge/Executive of the Issuer, on behalf of the Issuer. However, the Issuer has not and does not assume any responsibility as to the accuracy or completeness of any of the information in this Official Statement except for information furnished by the Issuer under the heading "The Issuer."

COUNTY OF CARROLL, KENTUCKY

By: /s/ Bobby Lee Westrick
County Judge/Executive

Appendix A

Kentucky Utilities Company

Kentucky Utilities Company ("KU"), incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. As of December 31, 2017, KU provided electricity to approximately 525,000 customers in 77 counties in central, southeastern and western Kentucky, approximately 28,000 customers in five counties in southwestern Virginia and three customers in Tennessee. KU's service area covers approximately 4,800 non-contiguous square miles. KU's coal-fired electric generating stations produce most of KU's electricity. The remainder is generated by natural gas fueled combined cycle combustion turbines, a hydroelectric power plant and natural gas and oil fueled combustion turbines. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 10 municipalities.

KU is a wholly-owned subsidiary of LG&E and KU Energy LLC and an indirect wholly-owned subsidiary of PPL Corporation. KU's affiliate, Louisville Gas and Electric Company ("LG&E"), is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and natural gas in Kentucky. KU's obligations under the Loan Agreement are solely its own, and not those of any of its affiliates. None of LG&E, PPL Corporation or KU's other affiliates will be obligated to make any payment on the Loan Agreement or the Bonds.

The information above concerning KU is only a summary and does not purport to be comprehensive. Additional information regarding KU, including audited financial statements, is available in the documents listed under the heading "Documents Incorporated by Reference," which documents are incorporated by reference herein.

Selected Financial Data
(Dollars in millions)

	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017	Year Ended December 31, 2017	Year Ended December 31, 2016	Year Ended December 31, 2015
Operating revenues	$ 885	$ 843	$ 1,744	$ 1,749	$ 1,728
Operating income[1]	$ 236	$ 244	$ 518	$ 531	$ 457
Net income	$ 148	$ 119	$ 259	$ 265	$ 234
Total assets	$ 8,353	$ 8,086	$ 8,254	$ 8,085	$ 8,011
Long-term debt obligations (including amounts due within one year) [1]	$2,329	$2,237	$ 2,328	$ 2,327	$ 2,326
Ratio of earnings to fixed charges[2]	4.6	4.9	5.2	5.3	5.3

Capitalization:

	June 30, 2018	% of Capitalization
Long-term debt and notes payable	$ 2,462	41.9%
Common equity	3,414	58.1%
Total capitalization	$ 5,876	100.0%

(1) Effective January 1, 2018, KU adopted accounting guidance that changes the income statement presentation of net periodic benefit cost. Retrospectively, this guidance requires the service cost component to be disaggregated from other components of net benefit cost and presented in the same income statement line items as other employee compensation costs arising from services rendered during the period. The other components of net periodic benefits are presented separately from the line items that include the service cost and outside of any subtotal of operating income. As a result, all periods reported in the June 30, 2018 Form 10-Q reflected the retrospective adoption of this guidance. Amounts reported in the table above for December 31, 2017, December 31, 2016 and December 31, 2015, also reflect retrospective reclassifications from other operation and maintenance expense to other income (expense) of $1 million, $2 million, and $2 million, respectively.

(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, 2017, and as of December 31 for each of those years, have been derived from the Company's audited financial statements. The selected financial data presented above for the six months ended June 30, 2018 and 2017 have been derived from the Company's unaudited financial statements for the six months ended June 30, 2018 and 2017. The Company's audited financial statements for the three fiscal years ended December 31, 2017, and as of December 31 for each of those years, are included in the Company's Form 10-K for the year ended December 31, 2017 incorporated by reference herein. The Company's unaudited financial statements for the six months ended June 30, 2018 are included in the Company's Form 10-Q for the quarter ended June 30, 2018 incorporated by reference herein. "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Form 10-K for the year ended December 31, 2017 and "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Form 10-Q for the quarter ended June 30, 2018, as well as the Combined Notes to Financial Statements as of December 31, 2017, 2016 and 2015 and the Combined Notes to Condensed Financial Statements (Unaudited) as of June 30, 2018 and December 31, 2017 and for the six-month periods ended June 30, 2018 and 2017, should be read in conjunction with the above information. Deloitte & Touche LLP audited the Company's financial statements for the fiscal years ended December 31, 2017 and December 31, 2016. Ernst & Young LLP audited the Company's financial statements for the fiscal year ended December 31, 2015.

Risk Factors

Investing in the Bonds involves risk. Please see the risk factors in KU's Annual Report on Form 10-K for the year ended December 31, 2017, which is incorporated by reference in this Appendix A. Before making an investment decision, you should carefully consider these risks as well as the other information contained or incorporated by reference in this Appendix A. Risks and uncertainties not presently known to KU or that KU currently deems immaterial may also impair its business operations, its financial results and the value of the Bonds.

Available Information

KU is subject to the information requirements of the Securities Exchange Act of 1934, as amended, and, accordingly, files reports and other information with the Securities and Exchange Commission (the "SEC"). Such reports and other information on file can be inspected and copied at the public reference facilities of the SEC, currently at 100 F Street, N.E., Room 1580, Washington, DC 20549; 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 public reference room.

Documents Incorporated by Reference

The following documents, as filed by KU with the SEC, are incorporated herein by reference:

1. Form 10-K Annual Report of KU for the year ended December 31, 2017;

2. Form 10-Q Quarterly Reports of KU for the quarters ended March 31, 2018 and June 30, 2018; and

3. Form 8-K Current Reports of KU filed with the SEC on January 16, 2018 and March 26, 2018.

All documents filed by KU 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 Official Statement and prior to the termination of the offering 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 Official Statement shall be deemed to be modified or superseded for purposes of this Official Statement to the extent that a statement contained in this Official Statement or in any other subsequently filed document which also is or is deemed to be incorporated by reference in this Official Statement 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 Official Statement.

KU hereby undertakes to provide without charge to each person (including any beneficial owner) to whom a copy of this Official Statement 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 he incorporated in this Official Statement by reference, other than certain exhibits to such documents. Requests for such copies should be directed to Treasurer, Kentucky Utilities Company, One Quality Street, Lexington, Kentucky 40507, telephone: (859) 255-2100.

Appendix B

(FORM OF OPINION OF BOND COUNSEL)

September 5, 2018

Re: $17,875,000 County of Carroll, Kentucky, Environmental Facilities Revenue Refunding Bonds, 2018 Series A (Kentucky Utilities Company Project)

We hereby certify that we have examined certified copies of the proceedings of record of the County of Carroll, Kentucky (the "**County**"), acting by and through its Fiscal Court as its duly authorized governing body, preliminary to and in connection with the issuance by the County of its Environmental Facilities Revenue Refunding Bonds, 2018 Series A (Kentucky Utilities Company Project), dated their date of issuance, in the aggregate principal amount of $17,875,000 (the "**2018 Series A Bonds**"). The 2018 Series A Bonds are issued under the provisions of Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "**Act**"), for the purpose of providing funds which will be used, with other funds provided by Kentucky Utilities Company (the "**Company**") for the current refunding of $17,875,000 aggregate principal amount of the County's Environmental Facilities Revenue Bonds, 2007 Series A (Kentucky Utilities Company Project), dated May 24, 2007 (the "**Refunded 2007 Series A Bonds**"), which were issued for the purpose of financing a portion of the costs of the acquisition, construction, installation, and equipping of certain solid waste disposal facilities to serve the Ghent Generating Station in Carroll County, Kentucky (the "**Project**"), as provided by the Act.

The 2018 Series A Bonds mature on February 1, 2026 and bear interest initially at the Long Term Rate, as defined in the Indenture, hereinafter described, subject to change as provided in such Indenture. The 2018 Series A Bonds will be subject to optional and mandatory redemption before maturity at the times, in the manner, and upon the terms set forth in the 2018 Series A Bonds. From such examination of the proceedings of the Fiscal Court of the County referred to above and from an examination of the Act, we are of the opinion that the County is duly authorized and empowered to issue the 2018 Series A Bonds under the laws of the Commonwealth of Kentucky now in force.

We have examined an executed counterpart of a certain Loan Agreement, dated as of August 1, 2018 (the "**Loan Agreement**"), by and between the County and the Company and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Loan Agreement, pursuant to which the County has agreed to issue the 2018 Series A 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 Refunded 2007 Series A 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 2018 Series A Bonds as they become due and payable. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Loan Agreement; that the Loan Agreement has been duly authorized, executed, and delivered by the County; and that the Loan Agreement is a legal, valid, and binding obligation of the County, enforceable in accordance with its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency, or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

We have also examined an executed counterpart of a certain Indenture of Trust, dated as of August 1, 2018 (the "**Indenture**"), by and between the County and U.S. Bank National Association, as trustee (the "**Trustee**"), securing the 2018 Series A Bonds and setting forth the covenants and undertakings of the County in connection with the 2018 Series A Bonds and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Indenture. Pursuant to the Indenture, certain of the County's rights under the Loan Agreement, including the right to receive payments thereunder, and all moneys and securities held by the Trustee in accordance with the Indenture (except moneys and securities in the Rebate Fund created thereby) have been assigned to the Trustee, as security for the holders of the 2018 Series A Bonds. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Indenture; that the Indenture has been duly authorized, executed, and delivered by the County; and that the Indenture is a legal, valid, and binding obligation upon the parties thereto according to its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency, or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

In our opinion the 2018 Series A 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 and limited obligations of the County entitled to the benefit of the security provided by the Indenture and enforceable in accordance with their terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency, or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought. The 2018 Series A Bonds are payable by the County solely and only from payments and other amounts derived from the Loan Agreement and as provided in the Indenture.

In our opinion, under existing laws, including current statutes, regulations, administrative rulings, and official interpretations by the Internal Revenue Service, subject to the exceptions and qualifications contained in the succeeding paragraphs, (i) interest on the 2018 Series A 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 2018 Series A 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 2018 Series A Bonds is a separate item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. The alternative minimum tax has been repealed with respect to corporations for taxable years beginning after December 31, 2017. In arriving at the opinion set forth in this paragraph as to the exclusion from gross income of interest on the 2018 Series A Bonds, we have assumed and this opinion is conditioned on, the accuracy of and continuing compliance by the Company and the County with representations and covenants set forth in the Loan Agreement and the Indenture which are intended to assure compliance with certain tax-exempt interest provisions of the Code. Such representations and covenants must be accurate and must be complied with after the issuance of the 2018 Series A Bonds in order that interest on the 2018 Series A 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 2018 Series A Bonds after the issuance of the 2018 Series A 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 2018 Series A Bonds. We express no opinion (i) regarding the exclusion of interest on any 2018 Series A 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 2018 Series A Bonds; or (ii) as to the treatment for purposes of federal income taxation of interest on the 2018 Series A Bonds upon a Determination of Taxability. We are further of the opinion that interest on the 2018 Series A Bonds is excluded from gross income of the recipients thereof for Kentucky income tax purposes and that the 2018 Series A 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 2018 Series A Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the 2018 Series A Bonds is further subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the 2018 Series A Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the 2018 Series A 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 2018 Series A Bonds. Ownership of the 2018 Series A Bonds may result in other federal tax consequences to certain taxpayers, and we express no opinion regarding any such collateral consequences arising with respect to the 2018 Series A Bonds.

We have received opinions of John R. Crockett III, General Counsel, Chief Compliance Officer, and Corporate Secretary 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. Nicholas Marsh, County Attorney of Carroll County, Kentucky, and relied upon said opinion with respect to the matters therein. The 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 2018 Series A 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

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Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(k)
Sponsoring Witness: Christopher M. Garrett

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission Form 1 (electric), Federal Energy Regulatory Commission Form 2 (gas), or Public Service Commission Form T (telephone).

Response:

See attached.

THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Kentucky Utilities Company	End of 2017/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/forms/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/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.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 18^{th} 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 1,168 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 168 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).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Kentucky Utilities Company	02 Year/Period of Report End of 2017/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)* One Quality Street, Lexington, KY 40507	
05 Name of Contact Person Rita A. Toubia	06 Title of Contact Person Mgr-Regulatory Acct & Report
07 Address of Contact Person *(Street, City, State, Zip Code)* 220 West Main Street, Louisville, KY 40202	

08 Telephone of Contact Person, *Including Area Code* (502) 627-4823	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)* 03/27/2018
02 Title Chief Financial Officer		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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	Regional Transmission Service Revenues (Account 457.1)	302	None
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	None
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	None
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	None
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	None
66	Generating Plant Statistics Pages	410-411	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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 Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	None
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

- [ ] Two copies will be submitted
- [X] No annual report to stockholders is prepared

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2017/Q4

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 W. Blake, Chief Financial Officer
220 West Main Street
Louisville, KY 40202

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Kentucky August 17, 1912
Virginia December 1, 1991

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Respondent furnishes electric services in Kentucky, Tennessee and Virginia.

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) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2017/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Kentucky Utilities Company (KU) is a wholly-owned subsidiary of LG&E and KU Energy LLC (LKE). LKE is a wholly-owned subsidiary of PPL Corporation (PPL), based in Allentown, PA.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	EXECUTIVE OFFICERS AT DECEMBER 31, 2017		
2			
3	Chairman of the Board and Chief Executive Officer	Victor A. Staffieri	
4	Chief Financial Officer	Kent W. Blake	
5	President and Chief Operating Officer	Paul W. Thompson	
6	Vice President-Human Resources	Gregory J. Meiman	
7	Senior Vice President-Operations	Lonnie E. Bellar	
8			
9	FORMER EXECUTIVE OFFICER DURING 2017		
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11	General Counsel, Chief Compliance Officer and		
12	Corporate Secretary	Gerald A. Reynolds	
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Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 104 Line No.: 3 Column: b

Victor A. Staffieri, Chairman of the Board and Chief Executive Officer, announced his retirement, effective March 15, 2018.

Schedule Page: 104 Line No.: 3 Column: c

Salary information for all officers is on file in the office of the respondent.

Schedule Page: 104 Line No.: 5 Column: b

Paul W. Thompson, Chief Operating Officer, was named President and Chief Operating Officer effective January 3, 2017 and was named Chairman of the Board, President and Chief Executive Officer, effective March 16, 2018.

Schedule Page: 104 Line No.: 7 Column: b

Lonnie E. Bellar, Senior Vice President, Operations, was named Chief Operating Officer, effective March 16, 2018.

Schedule Page: 104 Line No.: 12 Column: b

Gerald A. Reynolds, General Counsel, Chief Compliance Officer and Corporate Secretary, resigned September 21, 2017.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	BOARD OF DIRECTORS AT DECEMBER 31, 2017	
2		
3	Victor A. Staffieri, Chairman of the Board and Chief	
4	Executive Officer	220 West Main Street, Louisville, KY 40202
5	Paul W. Thompson, President and Chief Operating Officer	220 West Main Street, Louisville, KY 40202
6	Kent W. Blake, Chief Financial Officer	220 West Main Street, Louisville, KY 40202
7	Vincent Sorgi, Senior Vice President and	
8	Chief Financial Officer of PPL	2 North Ninth Street, Allentown, PA 18101
9	William H. Spence, Chairman, President and	
10	Chief Executive Officer of PPL	2 North Ninth Street, Allentown, PA 18101
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Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 105 Line No.: 3 Column: a

Victor A. Staffieri, Chairman of the Board and Chief Executive Officer, announced his retirement, effective March 15, 2018.

Schedule Page: 105 Line No.: 5 Column: a

Paul W. Thompson, Chief Operating Officer, was named President and Chief Operating Officer effective January 3, 2017 and was named Chairman of the Board, President and Chief Executive Officer, effective March 16, 2018. Lonnie E. Bellar, Senior Vice President, Operations, was named Chief Operating Officer and a director, effective March 16, 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[X] Yes
[ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Various	
2		
3	Open Access Transmission Tariff (OATT)	
4	Attachment O	Docket No. ER15-828-003
5		
6	OATT Schedule 1	Docket No. ER16-1543
7		
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Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 106 Line No.: 1 Column: a

Municipal	Rate Schedule No. for Amended Agreements	
Barbourville(1)	184	18.0.0
Bardstown(2)	185	13.2.0
Bardwell(1)	186	18.0.0
Berea(1)	197	18.0.0
Corbin(1)	188	18.0.0
Falmouth(1)	189	18.0.0
Frankfort(1)	190	18.0.0
Madisonville(1)	161	18.0.0
Nicholasville(2)	157	13.2.0
Providence(1)	195	18.0.0
Other		
Appalachian Power Company(3)	408	1.0.0

(1) Departing municipals, generation requirements service will terminate 4/30/19.
(2) Remaining municipals.
(3) Highknob Borderline Agreement.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20170501-5271	05/01/2017	ER13-2428	Annual update to Generation	Various
2				Formula Rates for	
3				Remaining Municipals	
4					
5	20170501-5509	05/01/2017	ER13-2428	Annual update to Generation	Various
6				Formula Rates for	
7				Departing Municipals	
8					
9	20171117-5100	11/17/2017	ER17-234-005	Tariff filing to record CCR	Various
10				ARO Settlement	
11				Departing Municipals	
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Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1				
2				
3				
4	Page 2 of 5	Schedule 10	3	2
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6	Page 3 of 5	Schedule 10	3	1
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Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 1062 Line No.: 4 Column: b

Transmission Gross Plant in Service excludes certain Virginia assets in compliance with FERC order in Docket No. ER02-2560.

Schedule Page: 1062 Line No.: 6 Column: b

Transmission Operation and Maintenance expenses exclude the amortization of certain regulatory assets approved by the Public Service Commission of Kentucky only.

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report / /	Year/Period of Report End of 2017/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.

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None.

2. None.

3. None.

4. None of a material nature.

5. None.

6. KU received FERC authorization in FERC Docket No. ES17-55-000 for up to $500 million in the form of money pool debt, commercial paper or any other type of short-term loan through November 30, 2019. KU's money pool balance was zero at December 31, 2017 and December 31, 2016. KU's commercial paper program limit is $350 million as of April 30, 2013. As of December 31, 2017 and December 31, 2016, the outstanding commercial paper balance is $45 million and $16 million, respectively.

   KU has a letter of credit facility totaling $198 million expiring September 24, 2020. The facility is consistent with the above FERC authorization and was approved by Kentucky Public Service Commission Order in Case No. 2008-00309 on September 16, 2008, by the Virginia State Corporation Commission on August 29, 2008, in Case No. PUE-2008-00077, and by the Tennessee Regulatory Authority on September 15, 2008, in Docket No. 08-00144. Letters of credit totaling $198 million were outstanding under this facility at December 31, 2017 and December 31, 2016.

   KU has a revolving credit facility totaling $400 million. The facility was approved by the Kentucky Public Service Commission Order, Case No. 2015-00137 on July 2, 2015, by the Virginia State Corporation Commission on June 18, 2015, in Case No. PUE-2014-00031, and by the Tennessee Regulatory Authority on August 3, 2015, in Docket No. 15-00056. The Kentucky Public Service Commission approved an extension of the credit facility in Case No. 2016-00360 on December 9, 2016. The Virginia State Corporation Commission authorized an extension of the facility under Case No. PUE-2014-00031 on November 21, 2016, and the Tennessee Regulatory Authority authorized the extension on December 29, 2016 in Docket No. 16-00119. On January 29, 2017, KU amended this revolving credit facility to extend the termination date from December 31, 2020 to January 29, 2022. There were no borrowings outstanding under this facility at December 31, 2017 and December 31, 2016.

7. None.

8. During the first quarter of 2017, exempt and non-exempt employees received routine wage increases in accordance with annual salary reviews. There were no changes to wage scales during the second quarter of 2017. The KU USW and the KU IBEW negotiated a wage increase of 3.0% effective July 23, 2017. Additionally, KU hourly employees received an annual increase of 3.0% effective July 23, 2017.

9. See Notes 4 and 10 of Notes to Financial Statements on page 123.

10. None.

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

11. N/A

12. See Notes to Financial Statements on page 123.

13. Victor A. Staffieri, Chairman of the Board and Chief Executive Officer, announced his retirement, effective March 15, 2018.

Paul W. Thompson, Chief Operating Officer, was named President and Chief Operating Officer effective January 3, 2017 and was named Chairman of the Board, President and Chief Executive Officer, effective March 16, 2018.

Lonnie E. Bellar, Vice President, Gas Distribution, was named Senior Vice President, Operations effective January 15, 2017. He was named Chief Operating Officer and a director, effective March 16, 2018. John. P. Malloy, Vice President, Customer Services, was named Vice President, Gas Distribution effective January 15, 2017. Elizabeth J. McFarland was named Vice President, Customer Services effective January 15, 2017.

George R. Siemens, Vice President, External Affairs, retired January 20, 2017. David J. Freibert was named Vice President, External Affairs effective January 21, 2017.

Laura M. Douglas, Vice President, Corporate Responsibility and Community Affairs, retired January 20, 2017.

John N. Voyles, Jr., Vice President, Transmission and Generation Services, retired March 31, 2017. R. Scott Straight was named Vice President, Project Engineering effective April 1, 2017.

Gerald A. Reynolds, General Counsel, Chief Compliance Officer and Corporate Secretary, resigned September 21, 2017. Dorothy E. O'Brien, Vice President and Deputy General Counsel, Legal and Environmental Affairs was named Vice President and Deputy General Counsel, Legal and Environmental Affairs and Corporate Secretary, effective October 9, 2017. She was named Vice President and Deputy General Counsel, effective January 1, 2018 and announced her retirement, effective April 17, 2018. John R. Crockett III was named General Counsel, Chief Compliance Officer and Corporate Secretary, effective January 1, 2018.

Valerie L. Scott, Controller, was named Vice President, Accounting effective January 1, 2018 and announced her retirement, effective February 19, 2018. Christopher M. Garrett, Director of Rates was named Controller, effective January 1, 2018.

14. KU is a participant in a cash pooling arrangement, but its proprietary capital ratio is above 30 percent.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2017/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	9,277,183,893	9,085,754,806
3	Construction Work in Progress (107)	200-201	321,167,940	180,793,120
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		9,598,351,833	9,266,547,926
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,238,141,782	3,051,197,812
6	Net Utility Plant (Enter Total of line 4 less 5)		6,360,210,051	6,215,350,114
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)		6,360,210,051	6,215,350,114
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		178,714	971,313
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	250,000	250,000
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		428,714	1,221,313
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		12,816,843	7,282,580
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		61,030	61,030
38	Temporary Cash Investments (136)		1,864,128	142,502
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		130,977,197	127,242,471
41	Other Accounts Receivable (143)		29,701,664	4,619,468
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,478,119	1,768,558
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		0	-38,001
45	Fuel Stock (151)	227	62,248,036	98,479,707
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	49,287,221	44,941,734
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	131,238	135,180

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2017/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	11,598,193	10,876,430
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		16,269,726	16,185,363
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		123,673	73,652
60	Rents Receivable (172)		548,548	568,224
61	Accrued Utility Revenues (173)		112,646,659	94,937,816
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
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)		426,796,037	403,739,598
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		18,055,102	17,220,275
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	416,947,625	445,233,227
73	Prelim. Survey and Investigation Charges (Electric) (183)		4,848,827	6,153,879
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	44,946,914	677,140,398
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	1,286,609	1,239,625
81	Unamortized Loss on Reaquired Debt (189)		8,826,063	9,436,063
82	Accumulated Deferred Income Taxes (190)	234	362,371,175	328,519,581
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		857,282,315	1,484,943,048
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		7,644,717,117	8,105,254,073

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 110 Line No.: 2 Column: c

Current period numbers reflected throughout the Form 1 do not include Purchase Accounting adjustments as presented in the Company's letter to the FERC dated August 3, 2017.

Schedule Page: 110 Line No.: 69 Column: d

Unamortized Debt Expenses (181) Without Purchase Accounting	$	19,221,807
Purchase Accounting Adjustment		(2,001,532)
Total for Unamortized Debt Expenses (181)	$	17,220,275

Schedule Page: 110 Line No.: 72 Column: d

Other Regulatory Assets (182.3) Without Purchase Accounting	$	443,231,695
Purchase Accounting Adjustment		2,001,532
Total for Other Regulatory Assets (182.3)	$	445,233,227

Schedule Page: 110 Line No.: 78 Column: d

Miscellaneous Deferred Debits (186) Without Purchase Accounting	$	46,422,241
Purchase Accounting Adjustment		630,718,157
Total for Miscellaneous Deferred Debits (186)	$	677,140,398

Schedule Page: 110 Line No.: 82 Column: d

Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$	319,366,234
Purchase Accounting Adjustment		9,153,347
Total for Accumulated Deferred Income Taxes (190)	$	328,519,581

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2017/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	308,139,978	308,139,978
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	583,858,083	2,616,446,834
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	321,289	321,289
11	Retained Earnings (215, 215.1, 216)	118-119	1,857,820,153	400,180,817
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	-599,389
16	Total Proprietary Capital (lines 2 through 15)		2,749,496,925	3,323,846,951
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,350,779,405	2,350,779,405
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	216,666
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		8,570,037	9,105,388
24	Total Long-Term Debt (lines 18 through 23)		2,342,209,368	2,341,890,683
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)		3,421,397	1,989,404
29	Accumulated Provision for Pensions and Benefits (228.3)		74,784,141	107,519,754
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		234,928,553	288,674,252
35	Total Other Noncurrent Liabilities (lines 26 through 34)		313,134,091	398,183,410
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		44,957,426	15,999,230
38	Accounts Payable (232)		159,294,010	90,647,549
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		53,209,388	56,193,623
41	Customer Deposits (235)		30,584,515	28,877,638
42	Taxes Accrued (236)	262-263	18,835,542	45,124,110
43	Interest Accrued (237)		16,161,240	16,021,675
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
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2017/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)		4,150,228	4,427,194
48	Miscellaneous Current and Accrued Liabilities (242)		18,630,719	18,017,570
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		345,823,068	275,308,589
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		842,196	1,521,114
57	Accumulated Deferred Investment Tax Credits (255)	266-267	93,857,854	95,774,040
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	1,381,941	1,542,817
60	Other Regulatory Liabilities (254)	278	744,309,851	168,515,639
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)		903,591,570	1,328,098,043
64	Accum. Deferred Income Taxes-Other (283)		150,070,253	170,572,787
65	Total Deferred Credits (lines 56 through 64)		1,894,053,665	1,766,024,440
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		7,644,717,117	8,105,254,073

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 112 Line No.: 7 Column: d

Other Paid-In Capital (208-211) Without Purchase Accounting	$	583,858,083
Purchase Accounting Adjustment		2,032,588,751
Total for Other Paid-In Capital (208-211)	$	2,616,446,834

Schedule Page: 112 Line No.: 11 Column: c

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$	1,857,820,153
Purchase Accounting Adjustment in accordance with Docket No. AC11-83-000	$	(1,418,324,387)
Amortization of Purchase Accounting Adjustments - (net of deferred taxes of $6,441,929)		(6,859,996)
Total for Retained Earnings (215, 215.1, 216) with Purchase Accounting Adjustments	$	432,635,770

As of December 31, 2017, in compliance with FERC Docket No. EL12-27-000, the amount in the Company's equity accounts available to be paid in the form of dividends is as follows:

Retained Earnings as of 12/31/2017 with Purchase Accounting Adjustments	$	432,635,770
Add: Stated capital account, reflecting pre-acquisition retained earnings less dividends applied to the account -- tracked in a separate purchase accounting general ledger		1,418,324,387
Add: Net after-tax losses attributable to amortization of pushdown accounting net assets and liabilities and impairment, if any, cumulative -- tracked on a separate purchase accounting general ledger		6,859,996
Retained Earnings as of 12/31/2017, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$	1,857,820,153
Retained Earnings prior to the 11/1/2010 acquisition		1,418,324,387
Cumulative post-acquisition net income		1,561,495,766
Cumulative post-acquisition dividends		(1,122,000,000)
Retained Earnings as of 12/31/2017, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$	1,857,820,153

Schedule Page: 112 Line No.: 11 Column: d

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$	1,826,711,397
Purchase Accounting Adjustment in accordance with FERC Docket No. AC11-83-000	$	(1,418,324,387)
Amortization of Purchase Accounting Adjustments - (net of deferred taxes of $7,438,679)		(8,206,193)
Total for Retained Earnings (215, 215.1, 216)	$	400,180,817

As of December 31, 2016, in compliance with FERC Docket No. EL12-27-000, the amount in the Company's equity accounts available to be paid in the form of dividends is as follows:

Retained Earnings as of 12/31/2016 with Purchase Accounting Adjustments	$	400,180,817
Add: Stated capital account, reflecting pre-acquisition retained earnings less dividends applied to the		

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FOOTNOTE DATA

account -- tracked in a separate purchase accounting general ledger -- a component of the amount on line 7 on page 112 (Other Paid-In Capital)		1,418,324,387
Add: Net after-tax losses attributable to amortization of pushdown accounting net assets and liabilities and impairment, if any, cumulative -- tracked on a separate purchase accounting general ledger -- a component of the amount on line 7 on page 112 (Other Paid-In-Capital)		8,206,193
Retained Earnings as of 12/31/2016, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$	1,826,711,397

Retained Earnings prior to the 11/1/2010 acquisition		1,418,324,387
Cumulative post-acquisition net income		1,304,387,010
Cumulative post-acquisition dividends		(896,000,000)
Retained Earnings as of 12/31/2016, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$	1,826,711,397

Schedule Page: 112 Line No.: 15 Column: d

Accumulated Other Comprehensive Income (219) Without Purchase Accounting	$	(1,813,204)
Purchase Accounting Adjustment		1,213,815
Total for Accumulated Other Comprehensive Income (219)	$	(599,389)

Schedule Page: 112 Line No.: 21 Column: d

The balance represents a purchase accounting adjustment.

Schedule Page: 112 Line No.: 60 Column: d

Other Regulatory Liabilities (254) Without Purchase Accounting	$	145,201,851
Purchase Accounting Adjustment		23,313,788
Total for Other Regulatory Liabilities (254)	$	168,515,639

Schedule Page: 112 Line No.: 64 Column: d

Accumulated Deferred Income Taxes - Other (283) Without Purchase Accounting	$	161,503,723
Purchase Accounting Adjustment		9,069,064
Total for Accumulated Deferred Income Taxes - Other (283)	$	170,572,787

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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	1,744,333,079	1,749,336,099		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	808,972,247	823,387,655		
5	Maintenance Expenses (402)	320-323	124,242,239	124,991,908		
6	Depreciation Expense (403)	336-337	238,531,335	222,140,274		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	15,572,213	11,964,819		
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)		924,553	151,221		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	41,520,581	39,970,768		
15	Income Taxes - Federal (409.1)	262-263	971,580	32,872,921		
16	- Other (409.1)	262-263	6,811,912	5,845,668		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	352,608,944	626,763,070		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	198,628,619	503,142,029		
19	Investment Tax Credit Adj. - Net (411.4)	266	10,450	4,601,305		
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)		52,419	92		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,391,485,016	1,389,547,488		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		352,848,063	359,788,611		

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STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,744,333,079	1,749,336,099					2
						3
808,972,247	823,387,655					4
124,242,239	124,991,908					5
238,531,335	222,140,274					6
						7
15,572,213	11,964,819					8
						9
						10
						11
924,553	151,221					12
						13
41,520,581	39,970,768					14
971,580	32,872,921					15
6,811,912	5,845,668					16
352,608,944	626,763,070					17
198,628,619	503,142,029					18
10,450	4,601,305					19
						20
						21
52,419	92					22
						23
						24
1,391,485,016	1,389,547,488					25
352,848,063	359,788,611					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)		352,848,063	359,788,611		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		59,509	8,835		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		47,247	4,059		
33	Revenues From Nonutility Operations (417)		834	-739		
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)		527,642	314,818		
38	Allowance for Other Funds Used During Construction (419.1)		289,221	380,925		
39	Miscellaneous Nonoperating Income (421)		-1,995,596	763,943		
40	Gain on Disposition of Property (421.1)		14,361	21,132		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		-1,151,276	1,484,855		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		3,519			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,526,801	1,538,158		
46	Life Insurance (426.2)		-1,756,634	-1,713,363		
47	Penalties (426.3)		49,017	33,116		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		714,900	998,340		
49	Other Deductions (426.5)		1,479,146	2,778,005		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		2,016,749	3,634,256		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	11,133	10,605		
53	Income Taxes-Federal (409.2)	262-263	-971,619	-1,584,811		
54	Income Taxes-Other (409.2)	262-263	-177,195	-289,023		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,908,469	209,363		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,895,056	10,876		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		1,926,636	1,846,203		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-4,050,904	-3,510,945		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		882,879	1,361,544		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		91,089,564	89,861,704		
63	Amort. of Debt Disc. and Expense (428)		2,634,250	2,551,475		
64	Amortization of Loss on Reaquired Debt (428.1)		610,000	659,866		
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)		5,836	2,024		
68	Other Interest Expense (431)		2,395,676	2,595,049		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		113,140	147,565		
70	Net Interest Charges (Total of lines 62 thru 69)		96,622,186	95,522,553		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		257,108,756	265,627,602		
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)		257,108,756	265,627,602		

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FOOTNOTE DATA

Schedule Page: 114 Line No.: 17 Column: d

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$	620,647,360
Amortization of Purchase Accounting Adjustment		6,115,710
Total for Provision for Deferred Income Taxes (410.1)	$	626,763,070

Schedule Page: 114 Line No.: 17 Column: h

See footnote data detail on Schedule Page: 114, Line No.: 17, Column d.

Schedule Page: 114 Line No.: 18 Column: d

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$	497,085,777
Amortization of Purchase Accounting Adjustment		6,056,252
Total for Provision for Deferred Income Taxes (411.1)	$	503,142,029

Schedule Page: 114 Line No.: 18 Column: h

See footnote data detail on Schedule Page: 114, Line No.: 18, Column d.

Schedule Page: 114 Line No.: 22 Column: c

The balance includes the sale of renewable energy credits associated with Brown Solar Facility in the amount of $52,333.

Schedule Page: 114 Line No.: 39 Column: d

Miscellaneous Nonoperating Income (421) Without Purchase Accounting	$	557,721
Amortization of Purchase Accounting Adjustment		206,222
Total for Miscellaneous Nonoperating Income (421)	$	763,943

Schedule Page: 114 Line No.: 46 Column: c

The balance includes the increase in the cash surrender value less the monthly premium amounts that are paid from the cash surrender value balance.

Schedule Page: 114 Line No.: 46 Column: d

The balance includes the increase in the cash surrender value less the monthly premium amounts that are paid from the cash surrender value balance.

Schedule Page: 114 Line No.: 55 Column: d

Provision for Deferred Income Taxes (410.2) Without Purchase Accounting	$	124,812
Amortization of Purchase Accounting Adjustment		84,551
Total for Provision for Deferred Income Taxes (410.2)	$	209,363

Schedule Page: 114 Line No.: 56 Column: d

Provision for Deferred Income Taxes (411.2) Without Purchase Accounting	$	6,545
Amortization of Purchase Accounting Adjustment		4,331
Total for Provision for Deferred Income Taxes (411.2)	$	10,876

Schedule Page: 114 Line No.: 62 Column: d

Interest on Long-Term Debt (427) Without Purchase Accounting	$	90,014,554
Amortization of Purchase Accounting Adjustment		(152,850)
Total for Interest on Long-Term Debt (427)	$	89,861,704

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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		1,826,711,397	382,553,214
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Rounding			1
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			1
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		257,108,756	265,627,602
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Without Par Value		-226,000,000	(248,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-226,000,000	(248,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,857,820,153	400,180,817
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

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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)		1,857,820,153	400,180,817
	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)			

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FOOTNOTE DATA

Schedule Page: 118 Line No.: 48 Column: c

See data detail on Schedule Page: 112, Line No.: 11, Column: c.

Schedule Page: 118 Line No.: 48 Column: d

See data detail on Schedule Page: 112, Line No.: 11, Column: d.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	257,108,756	265,627,602
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	238,531,335	222,140,274
5	Amortization of Plant and Regulatory Debits and Credits	22,087,024	22,549,127
6	Other Noncash Charges (Credits) to Income	8,120,286	6,498,893
7			
8	Deferred Income Taxes (Net)	154,148,134	123,647,963
9	Investment Tax Credit Adjustment (Net)	-1,916,186	2,755,102
10	Net (Increase) Decrease in Receivables	-22,483,349	-22,210,537
11	Net (Increase) Decrease in Inventory	32,447,519	-5,665,098
12	Net (Increase) Decrease in Allowances Inventory	3,943	5,176
13	Net Increase (Decrease) in Payables and Accrued Expenses	-18,846,966	26,077,844
14	Net (Increase) Decrease in Other Regulatory Assets	4,684,726	8,914,996
15	Net Increase (Decrease) in Other Regulatory Liabilities	569,474	-5,197,782
16	(Less) Allowance for Other Funds Used During Construction	289,221	380,925
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-41,961,343	-38,061,841
19	Change in Other Deferred Debits	1,636,400	165,462
20	Change in Other Deferred Credits	-160,876	-135,966
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	633,679,656	606,730,290
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-412,396,079	-335,536,331
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-289,221	-380,925
31	Other (provide details in footnote):	-20,016,181	-15,313,676
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-432,123,039	-350,469,082
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
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)		

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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):	3,670,780	1,263,360
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-428,452,259	-349,205,722
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		96,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		20,000,000
65			
66	Net Increase in Short-Term Debt (c)	28,958,196	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	28,958,196	116,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-96,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-929,704	-1,493,479
77			
78	Net Decrease in Short-Term Debt (c)		-32,000,000
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-226,000,000	-248,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-197,971,508	-261,493,479
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	7,255,889	-3,968,911
87			
88	Cash and Cash Equivalents at Beginning of Period	7,486,112	11,455,023
89			
90	Cash and Cash Equivalents at End of period	14,742,001	7,486,112

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FOOTNOTE DATA

Schedule Page: 120 Line No.: 6 Column: b

Amortization of Debt Discount and Debt Issuance Costs	$	3,241,726
Net Change in Key Man Life Insurance		(1,736,370)
Other Comprehensive Income		1,813,204
Provision for Pension and Postretirement Benefits		4,505,859
Amortization of Research and Development and Demonstration Expenditures		287,949
Loss on Sale of Assets		7,918
Total	$	8,120,286

Schedule Page: 120 Line No.: 6 Column: c

Amortization of Debt Discount and Debt Issuance Costs	$	3,213,031
Net Change in Key Man Life Insurance		(1,703,922)
Other Comprehensive Income		(185,988)
Provision for Pension and Postretirement Benefits		4,997,939
Gain on Sale of Assets		(16,751)
Property Write-off		413,977
Change in Deferred Income Taxes - Purchase Accounting		59,459
Change in Unappropriated Undistributed Subsidiary Earnings - Purchase Accounting		(126,002)
Change in Pollution Control Bonds - Purchase Accounting		(152,850)
Total	$	6,498,893

Schedule Page: 120 Line No.: 18 Column: b

Net change in Prepayments and Other Assets	$	(84,364)
Net change in Customer Advances for Construction		(678,918)
Net change in Asset Retirement Obligations		(1,315,363)
Pension and Postretirement Funding		(22,917,394)
Expenditures for Asset Retirement Obligations		(20,116,432)
Net change in Other Liabilities		3,151,127
Rounding		1
Total	$	(41,961,343)

Schedule Page: 120 Line No.: 18 Column: c

Net change in Prepayments and Other Assets	$	(8,672,051)
Net change in Customer Advances for Construction		(447,571)
Net change in Asset Retirement Obligations		(2,990,426)
Pension and Postretirement Funding		(20,740,400)
Expenditures for Asset Retirement Obligations		(8,644,817)
Net change in Other Liabilities		3,433,423
Rounding		1
Total	$	(38,061,841)

Schedule Page: 120 Line No.: 31 Column: b

Costs of removal of utility plant	$	(20,016,181)

Schedule Page: 120 Line No.: 31 Column: c

Costs of removal of utility plant	$	(15,313,676)

Schedule Page: 120 Line No.: 53 Column: b

Proceeds for Key Man Life Insurance	$	3,670,780

Schedule Page: 120 Line No.: 53 Column: c

Proceeds for Key Man Life Insurance	$	1,263,360

Schedule Page: 120 Line No.: 64 Column: c

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FOOTNOTE DATA

LG&E and KU Energy LLC Equity Contribution	$	20,000,000

Schedule Page: 120 Line No.: 76 Column: b

Debt issuance costs	$	(929,704)

Schedule Page: 120 Line No.: 76 Column: c

Debt issuance costs	$	(1,493,479)

Schedule Page: 120 Line No.: 90 Column: b

Cash (131)	$	12,816,843
Working Fund (135)		61,030
Temporary Cash Investments (136)		1,864,128
Total Cash and Cash Equivalents	$	14,742,001

Schedule Page: 120 Line No.: 90 Column: c

Cash (131)	$	7,282,580
Working Fund (135)		61,030
Temporary Cash Investments (136)		142,502
Total Cash and Cash Equivalents	$	7,486,112

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report / /	Year/Period of Report End of 2017/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

GLOSSARY OF TERMS AND ABBREVIATIONS

KU - Kentucky Utilities Company, a public utility subsidiary of LKE engaged in the regulated generation, transmission, distribution and sale of electricity, primarily in Kentucky.

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.

LKE - LG&E and KU Energy LLC, a subsidiary of PPL and the parent of LG&E, KU and other subsidiaries.

LKS - LG&E and KU Services Company, a subsidiary of LKE that provides administrative, management and support services primarily to LKE and its subsidiaries.

PPL - PPL Corporation, the parent holding company of LKE and other subsidiaries.

PPL Services - PPL Services Corporation, a subsidiary of PPL that provides administrative, management and support services to PPL and its subsidiaries.

Other terms and abbreviations

401(h) account(s) - a sub-account established within a qualified pension trust to provide for the payment of retiree medical costs.

Advanced Metering System - meters and meter reading systems that provide two-way communication capabilities, which communicate usage and other relevant data to KU at regular intervals, and are also able to receive information from KU, such as software upgrades and requests to provide meter readings in real time.

AFUDC - allowance for funds used during construction. The cost of equity and debt funds used to finance construction projects of regulated businesses, which is capitalized as part of construction costs.

ARO - asset retirement obligation.

CCR(s) - Coal Combustion Residual(s). CCRs include fly ash, bottom ash and sulfur dioxide scrubber wastes.

Clean Air Act - federal legislation enacted to address certain environmental issues related to air emissions, including acid rain, ozone and toxic air emissions.

Clean Water Act - federal legislation enacted to address certain environmental issues relating to water quality including effluent discharges, cooling water intake, and dredge and fill activities.

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 certain plant, equipment, property or facility for furnishing of utility service to the public.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Distribution Automation - advanced grid intelligence enabling KU to perform remote monitoring and control, circuit segmentation and "self-healing" of select distribution system circuits, improving grid reliability and efficiency.

DSM - Demand Side Management. Pursuant to Kentucky Revised Statute 278.285, the KPSC may determine the reasonableness of DSM programs proposed by any utility under its jurisdiction. DSM programs consist of energy efficiency programs intended to reduce peak demand and delay the investment in additional power plant construction, provide customers with tools and information regarding their energy usage and support energy efficiency.

ECR - Environmental Cost Recovery. Pursuant to Kentucky Revised Statute 278.183, 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 that apply to coal combustion wastes and by-products from the production of energy from coal.

ELG(s) - Effluent Limitation Guidelines, regulations promulgated by the EPA.

EPA - Environmental Protection Agency, a U.S. government agency.

FERC - Federal Energy Regulatory Commission, the U.S. federal agency that regulates, among other things, interstate transmission and wholesale sales of electricity, hydroelectric power projects and related matters.

GAAP - Generally Accepted Accounting Principles in the U.S.

GHG - greenhouse gas(es).

IRS - Internal Revenue Service, a U.S. government agency.

KPSC - Kentucky Public Service Commission, the state agency that has jurisdiction over the regulation of rates and service of utilities in Kentucky.

KU 2010 Mortgage Indenture - KU's Indenture, dated as of October 1, 2010, to The Bank of New York Mellon, as supplemented.

kWh - kilowatt hour, basic unit of electrical energy.

LIBOR - London Interbank Offered Rate.

MW - megawatt, one thousand kilowatts.

NAAQS - National Ambient Air Quality Standards periodically adopted pursuant to the Clean Air Act.

NERC - North American Electric Reliability Corporation.

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NOTES TO FINANCIAL STATEMENTS (Continued)

NGCC - Natural gas-fired combined-cycle generating plant.

NPNS - the normal purchases and normal sales exception as permitted by derivative accounting rules. Derivatives that qualify for this exception may receive accrual accounting treatment.

OCI - other comprehensive income or loss.

OVEC - Ohio Valley Electric Corporation, located in Piketon, Ohio, an entity in which KU owns a 2.50% interest, 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 capacities of 2,120 MW.

PP&E - property, plant and equipment.

RCRA - Resource Conservation and Recovery Act of 1976.

RFC - Reliability*First* Corporation, one of eight regional entities with delegated authority from NERC that work to safeguard the reliability of the bulk power systems throughout North America.

SCRs - selective catalytic reduction, a pollution control process for the removal of nitrogen oxide from exhaust gas.

Scrubber - an air pollution control device that can remove particulates and/or gases (primarily sulfur dioxide) from exhaust gases.

SEC - the U.S. Securities and Exchange Commission, a U.S. government agency primarily responsible to protect investors and maintain the integrity of the securities markets.

SERC - SERC Reliability Corporation, one of eight regional entities with delegated authority from NERC that work to safeguard the reliability of the bulk power systems throughout North America.

Superfund - federal environmental statute that addresses remediation of contaminated sites; states also have similar statutes.

TCJA - Tax Cuts and Jobs Act. Comprehensive U.S. federal tax legislation enacted on December 22, 2017.

VEBA - Voluntary Employee Benefit Association Trust, accounts for health and welfare plans for future benefit payments for employees, retirees or their beneficiaries.

VSCC - Virginia State Corporation Commission, the state agency that has jurisdiction over the regulation of Virginia corporations, including utilities.

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As permitted by the FERC for the Year Ended December 31, 2017 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, 2017, which was filed with the SEC on February 22, 2018. Accordingly, these Notes do not reflect updated information since this filing date except for information disclosed in Note 18.

NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

General

Capitalized terms and abbreviations appearing in the notes to financial statements are defined 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:

Reporting Classifications	FERC reporting	GAAP reporting
Cost of removal obligations	Reported in accumulated depreciation.	Reported in regulatory liabilities.
Certain retirement work in progress amounts	Reported in accumulated depreciation.	Reported in asset retirement obligations.
Certain intangible assets	Reported in utility plant and accumulated depreciation.	Reported in other intangibles.
Debt maturity classification	Reported in total in the long-term debt section.	Reported separately in current liabilities for the short-term portion and in long-term debt for the long-term portion.
Deferred taxes	Reported gross on the Balance Sheet (a deferred asset and a deferred liability are recorded).	Reported as a net asset or net liability.
Income taxes	Income taxes, deferred taxes and investment tax credits are reported on separate lines on the Income Statement.	Income taxes, deferred taxes and investment tax credits are netted on a single line on the Income Statement.
Utility plant acquired before November 1, 2010	Reported at original cost.	Restated to net fair value as of November 1, 2010.

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NOTES TO FINANCIAL STATEMENTS (Continued)

Reporting Classifications	FERC reporting	GAAP reporting
Regulatory asset maturity classification	Reported in total in deferred debits.	Short-term regulatory assets are reported in current assets and long-term regulatory assets are reported in other noncurrent assets.
Regulatory liability maturity classification	Reported in total in deferred credits.	Short-term regulatory liabilities are reported in current liabilities and long-term regulatory liabilities are reported in deferred credits and other noncurrent liabilities.
Deferred financing costs	Reported as deferred debits.	Reported as contra-liabilities and netted with long-term debt.
Amounts presented within the Balance Sheet and Income Statement	Reported without purchase accounting adjustments.	Reported with purchase accounting adjustments.

Beginning in 2017, certain balances have been adjusted to reflect amounts at the original cost basis of accounting. Prior to 2017, certain amounts reflected the impact of purchase business combination accounting. While both presentations conform to the FERC USofA, the 2017 presentation more closely aligns with the manner in which KU's rates are calculated and reflective of amounts included in separate regulatory filings. This change in the basis of presentation is included in the 2017 regulatory basis financial statements only; the 2016 regulatory basis financial statements have not been revised. As GAAP requires a comparative presentation; we have reconciled the changes that would have been made to the 2016 statements in the Footnote Data (pages 450.X) to the regulatory basis financial statements had they been revised. This change in presentation was communicated to the FERC by letter dated August 3, 2017 and a related phone conversation. Purchase accounting amounts as of December 31, 2017 are presented below:

FERC Line Item	Current Year
Utility Plant (101-106, 114)	$(1,671,107,825)
Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	(1,671,107,825)
Unamortized Debt Expenses (181)	(1,874,279)
Other Regulatory Assets (182.3)	1,874,279
Miscellaneous Deferred Debits (186) (a)	628,197,515
Accumulated Deferred Income Taxes (190)	5,352,156
Other Paid-In Capital (208-211)	2,032,588,751
Retained Earnings (215, 215.1, 216)	(1,425,184,383)
Other Regulatory Liabilities (254)	20,793,147
Accum. Deferred Income Taxes-Other (283)	5,352,156
Provision for Deferred Income Taxes (410.1)	5,041,212

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NOTES TO FINANCIAL STATEMENTS (Continued)

FERC Line Item	Current Year
Provision for Deferred Inc. Taxes (410.2)	3,045,494
Provision for Deferred Income Taxes-Cr. (411.1)	4,956,929
Provision for Deferred Income Taxes-Cr. (411.2)	2,272,705
Miscellaneous Nonoperating Income (421)	1,986,603
Interest on Long-Term Debt (427)	(216,666)

(a) Includes goodwill amounts of $607,404,368.

Business and Consolidation

KU is engaged in the generation, transmission, distribution and sale of electricity in Kentucky. KU also serves customers in Virginia (under the Old Dominion Power name) and in Tennessee under the KU name.

KU has no controlling interest in any variable interest entities. All other investments are carried at cost or fair value.

KU's financial statements 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 9 for additional information.

Regulation

KU is a cost-based rate-regulated utility for which rates are set by regulators to enable KU to recover the costs of providing electric service and to provide a reasonable return to its shareholder. Base rates are generally established based on a future test period. 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 regulatory 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

KU's 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.

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NOTES TO FINANCIAL STATEMENTS (Continued)

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Loss Accruals

Potential losses are accrued when (1) information is available that indicates it is "probable" that a loss has been incurred, given the likelihood of the uncertain future events and (2) the amount of the loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." KU continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events.

The accrual of contingencies that might result in gains is not recorded, unless realization is assured.

Price Risk Management

Interest rate contracts are used to hedge exposure to changes in the fair value of debt instruments and to hedge exposure to variability in expected cash flows associated with existing floating-rate debt instruments or forecasted fixed-rate issuances of debt. Similar derivatives may receive different accounting treatment, depending on management's intended use and documentation.

Certain contracts may not meet the definition of a derivative because they lack a notional amount or a net settlement provision. In cases where there is no net settlement provision, markets are periodically assessed to determine whether market mechanisms have evolved that would facilitate net settlement. Certain derivative contracts may be excluded from the requirements of derivative accounting treatment because NPNS has been elected. These contracts are accounted for using accrual accounting. Contracts that have been classified as derivative contracts are reflected on the Balance Sheets at fair value. The portion of derivative positions that deliver within a year are included in "Current Assets" and "Current Liabilities," while the portion of derivative positions that deliver beyond a year are recorded in "Other Noncurrent Assets" and "Deferred Credits and Other Noncurrent Liabilities." KU considers intra-month transactions to be spot activity, which is not accounted for as a derivative.

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 classification of the hedged items.

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NOTES TO FINANCIAL STATEMENTS (Continued)

Processes exist that allow for subsequent review and validation of the contract information as it relates to interest rate derivatives. The accounting department provides the treasury department with guidelines on appropriate accounting classifications for various contract types and strategies. 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, to the extent the forecasted debt issuances remain probable of occurring.

- 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.

See Notes 12 and 13 for additional information on derivatives.

Revenue

<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 meters being read and bills rendered 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. Any difference between estimated and actual revenues is adjusted the following month.

Accounts Receivable

Accounts receivable are reported on the Balance Sheets at the gross outstanding amount.

<u>Allowance for Doubtful Accounts</u>

Accounts receivable collectability is evaluated using a combination of factors, including past due status based on contractual terms, trends in write-offs and the age of the receivable. 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.

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NOTES TO FINANCIAL STATEMENTS (Continued)

The changes in the allowance for doubtful accounts at December 31 were:

	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions (a)	Balance at End of Period
2017	$ 2	$ 4	$ (1)	$ 4	$ 1
2016	2	4	-	4	2

(a) Primarily related to uncollectible accounts written off.

Cash

Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered to be cash equivalents.

Fair Value Measurements

KU values certain financial and nonfinancial assets and liabilities at fair value. Generally, the most significant fair value measurements relate to price risk management assets and liabilities, investments in securities in defined benefit plans, and cash and cash equivalents. KU uses, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques and option-pricing models) and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

KU classifies fair value measurements within one of three levels in the fair value hierarchy. The level assigned to a fair value measurement is based on the lowest level input that is significant to the fair value measurement in its entirety. The three levels of the fair value hierarchy are as follows:

- **Level 1** - quoted prices (unadjusted) in active markets for identical assets or liabilities that are accessible at the measurement date. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

- **Level 2** - inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for substantially the full term of the asset or liability.

- **Level 3** - unobservable inputs that management believes are predicated on the assumptions market participants would use to measure the asset or liability at fair value.

Assessing the significance of a particular input requires judgment that considers factors specific to the asset or liability. As such, KU's assessment of the significance of a particular input may affect how the assets and liabilities are classified within the fair value hierarchy.

Investments

Generally, the original maturity date of an investment and management's intent and ability to sell an investment prior to its original maturity determine the classification of investments as either short-term or long-term. Investments that would otherwise be classified as short-term, but are restricted as to withdrawal or use for other than current operations or are clearly designated for expenditure in the acquisition or construction of noncurrent assets or for the liquidation of long-term debts, are classified as long-term.

Short-term Investments

Short-term investments generally include certain deposits as well as securities that are considered highly liquid or provide for periodic reset of interest rates. Investments with original maturities greater than three months and less than a year, as well as investments with original maturities of greater than a year that management has the ability and intent to sell within a year, are included in “Other current assets” on the Balance Sheets.

Cost Method Investment

KU has an investment in OVEC, which is accounted for using the cost method. The investment is recorded in "Other noncurrent assets" on the Balance Sheets. KU and 11 other electric utilities are equity owners of OVEC. OVEC's power is currently supplied to KU and 12 other companies affiliated with the various owners. KU owns 2.5% of OVEC's common stock. Pursuant to a power purchase agreement, KU is contractually entitled to its ownership percentage of OVEC's output, which is approximately 53 MW.

KU's investment in OVEC is not significant. The direct exposure to loss as a result of KU's involvement with OVEC is generally limited to the value of its investment; however, KU is conditionally responsible for a pro-rata share of certain OVEC obligations, pursuant to its power purchase contract with OVEC. As part of PPL's acquisition of LKE, the value of the power purchase contract was recorded as an intangible asset with an offsetting regulatory liability, both of which are being amortized using the units-of-production method until March 2026. See Notes 4, 10 and 14 for additional discussion of 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 for constructed assets includes material, labor, contractor costs, certain overheads and financing costs, where applicable. The cost of repairs and minor

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replacements are charged to expense as incurred. KU records costs associated with planned major maintenance projects in the period in which the costs are incurred. No costs associated with planned major maintenance projects are accrued to PP&E in advance of the period in which the work is performed. KU accrues costs of removal net of estimated salvage value through depreciation, which is included in the calculation of customer rates over the assets' depreciable lives in accordance with regulatory practices. All ARO depreciation expense is reclassified to a regulatory asset. See "Asset Retirement Obligations" below, Note 4, and Note 15 for additional information.

KU generally does not record AFUDC, except for certain instances in its FERC approved rates charged to its municipal customers, as a return is provided on construction work in progress.

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. KU's weighted-average rates of depreciation for regulated utility plant were 3.66% and 3.77% at December 31, 2017 and 2016.

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 obtain an initial license and renew or extend terms of licenses are capitalized as intangible assets.

When determining the useful life of an intangible asset, including intangible assets that are renewed or extended, KU considers:

- the expected use of the asset;
- the expected useful life of other assets to which the useful life of the intangible asset may relate;
- legal, regulatory, or contractual provisions that may limit the useful life;
- the company's historical experience as evidence of its ability to support renewal or extension;
- the effects of obsolescence, demand, competition, and other economic factors; and,
- the level of maintenance expenditures required to obtain the expected future cash flows from the asset.

Asset Impairment (Excluding Investments)

KU reviews long-lived assets that are subject to depreciation or amortization, including finite-lived intangibles,

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for impairment when events or circumstances indicate carrying amounts 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.

KU reviews goodwill 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 in circumstances when a portion of goodwill has been allocated to a business to be disposed. KU is a single reporting unit.

KU may elect either to initially make a qualitative evaluation about the likelihood of an impairment of goodwill or to bypass the qualitative evaluation and test goodwill for impairment using a two-step quantitative test. If the qualitative evaluation (referred to as "step zero") is elected and the assessment results in a determination that it is not more likely than not that the fair value of a reporting unit is less than the carrying amount, the two-step quantitative impairment test is not necessary. However, the quantitative impairment test is required if management concludes it is more likely than not that the fair value of a reporting unit is less than the carrying amount based on the step zero assessment.

If the carrying amount of the reporting unit, 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.

KU elected to perform the qualitative step zero evaluation of goodwill as of October 1, 2017. This evaluation considered the excess of fair value over the carrying value of KU’s reporting unit that was calculated during step one of the quantitative impairment tests performed in the fourth quarter of 2015, and the relevant events and circumstances that occurred since those tests were performed including:

- current year financial performance versus the prior year,
- changes in planned capital expenditures,
- the consistency of forecasted free cash flows,
- earnings quality and sustainability,
- changes in market participant discount rates,
- changes in long-term growth rates,
- changes in PPL’s market capitalization, and
- the overall economic and regulatory environments in which these regulated entities operate.

Based on this evaluation, management concluded it was not more likely than not that the fair value of KU's reporting unit was less than its carrying value. As such, the two-step quantitative impairment test was not performed and no impairment was recognized.

Asset Retirement Obligations

KU records liabilities to reflect various legal obligations associated with the retirement of long-lived assets. Initially, this obligation is measured at fair value and offset with an increase in the value of the capitalized asset, which is depreciated over the asset's useful life. Until the obligation is settled, the liability is increased through the recognition of accretion expense. All ARO accretion and depreciation expenses are reclassified as a regulatory asset. ARO regulatory assets associated with certain CCR projects are amortized to expense in accordance with regulatory approvals. For other AROs, at the time of retirement, the related ARO regulatory asset is offset against the associated cost of removal regulatory liability, PP&E and ARO liability.

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 generally amortized over the remaining life of the associated long-lived asset. See Note 15 for additional information on AROs.

Compensation and Benefits

Defined Benefits

KU does not directly sponsor any defined benefit plan. KU participates in defined benefit pension and other postretirement plans sponsored by LKE. LKE allocates a portion of the liability and net periodic defined benefit pension and other postretirement costs of certain plans to KU based on its participation in those plans. An asset or liability is recorded to recognize the funded status of all defined benefit plans with an offsetting entry to regulatory assets or liabilities. Consequently, the funded status of all defined benefit plans is fully recognized on the Balance Sheets.

The expected return on plan assets is determined based on a market-related value of plan assets, which is calculated by rolling forward the prior year market-related value with contributions, disbursements and long-term expected return on investments. One-fifth of the difference between the actual value and the expected value is added (or subtracted if negative) to the expected value to determine the new market-related value.

LKE uses an accelerated amortization method for the recognition of gains and losses for its defined benefit pension plans. Under the accelerated method, actuarial gains and losses in excess of 30% of the plan's projected benefit obligation are amortized on a straight-line basis over one-half of the expected average remaining service of active plan participants. Actuarial gains and losses in excess of 10% of the greater of the plan's projected benefit obligation or the market-related value of plan assets and less than 30% of the plan's projected benefit obligation are amortized on a straight-line basis over the expected average remaining service period of active plan participants.

See Note 4 for a discussion of the regulatory treatment of defined benefit costs and Note 8 for a discussion of defined benefits.

Taxes

Income Taxes

KU is included in PPL's consolidated U.S. federal income tax return.

KU has completed or made reasonable estimates of the effects of the TCJA and reflected these amounts in its December 31, 2017 financial statements. KU continues to evaluate the application of the TCJA and has used significant management judgement to make certain assumptions concerning the application of various components of the law in the calculation of 2017 income tax expense. The current and deferred components of the income tax expense calculations that KU considers provisional due to uncertainty either with respect to the technical application of the law or the quantification of the impact of the law include (but are not limited to) tax depreciation. KU believes that classification of these items as provisional is appropriate. KU has accounted for these items based on their interpretation of the TCJA.

Further interpretive guidance on the TCJA from the IRS, Treasury, the Joint Committee on Taxation through its "Blue Book" or from Congress in the form of Technical Corrections may differ from KU's interpretation of the TCJA.

Significant management judgment is required in developing KU's provision for income taxes, primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and valuation allowances on deferred tax assets.

Significant management judgment is also required to determine the amount of benefit to be recognized in relation to an uncertain tax position. KU uses a two-step process to evaluate tax positions. The first step requires KU 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 KU 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 KU's financial statements in future periods.

Deferred income taxes reflect the net future tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes, as well as the tax effects of net operating losses and tax credit carryforwards.

KU records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. KU considers the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies in initially recording and subsequently reevaluating the need for valuation allowances. If KU determines that it is able to realize deferred tax assets in the future in excess of recorded net

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deferred tax assets, adjustments to the valuation allowances increase income by reducing tax expense in the period that such determination is made. Likewise, if KU determines that it is not able to realize all or part of net deferred tax assets in the future, adjustments to the valuation allowances would decrease income by increasing tax expense in the period that such determination is made.

KU defers investment tax credits when the credits are utilized and amortize the deferred amounts over the average lives of the related assets.

KU recognizes interest and penalties in "Income Taxes" on its Statements of Income.

See Note 3 for additional discussion regarding income taxes, including the impact of the TCJA.

KU’s provision for 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 Sheets in noncurrent "Regulatory assets" or "Regulatory liabilities."

KU’s income tax provision is calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if KU filed a separate return. Tax benefits are not shared between companies. KU is only entitled to tax benefits that it generated. The effect of PPL filing a consolidated tax return is taken into account in the settlement of current taxes and the recognition of deferred taxes. KU did not have an intercompany tax payable or receivable at December 31, 2017 and an intercompany tax payable of $29 million at December 31, 2016.

Taxes, Other Than Income

KU presents sales taxes in "Other current liabilities" on the Balance Sheets. 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.

Other

Leases

KU evaluates whether arrangements entered into contain leases for accounting purposes. See Note 7 for additional information.

Fuel, Materials and Supplies

Fuel, materials and supplies are valued using the average cost method. Fuel costs for electric generation are charged to expense as used. See Note 4 for further discussion of the fuel adjustment clause.

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"Fuel, materials and supplies" on the Balance Sheets consisted of the following at December 31:

	2017	2016
Fuel	$ 62	$ 98
Materials and supplies	61	56
Total	$ 123	$ 154

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 10 for further discussion of recorded and unrecorded guarantees.

2. Preferred Securities

KU is authorized to issue up to 5,300,000 shares of preferred stock and 2,000,000 shares of preference stock without par value. KU had no preferred or preference stock issued or outstanding in 2017 or 2016.

3. Income and Other Taxes

Tax Cuts and Jobs Act (TCJA)

On December 22, 2017, President Trump signed into law the TCJA. Substantially all of the provisions of the TCJA are effective for taxable years beginning after December 31, 2017. The TCJA includes significant changes to the taxation of corporations, including provisions specifically applicable to regulated public utilities. The more significant changes that impact KU are:

- The reduction in the U.S. federal corporate income tax rate from a top marginal rate of 35% to a flat rate of 21%, effective January 1, 2018;
- Limitations on the tax deductibility of interest expense, with an exception to these limitations for regulated public utilities;
- Full current year expensing of capital expenditures with an exception for regulated public utilities that qualify for the exception to the interest expense limitation; and
- The continuation of certain rate normalization requirements for accelerated depreciation benefits. For non-regulated businesses, the TCJA generally provides for full expensing of property acquired after September 27, 2017.

Under GAAP, the tax effect of changes in tax laws must be recognized in the period in which the law is enacted, or December 2017 for TCJA. The changes enacted by the TCJA were recorded as an adjustment to KU's deferred tax provision.

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The components of these adjustments are discussed below:

Reduction of U.S. Federal Corporate Income Tax Rate

GAAP requires deferred tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. Thus, at the date of enactment, KU's deferred taxes were remeasured based upon the new U.S. federal corporate income tax rate of 21%. The changes in deferred taxes were, in large part, recorded as an offset to either a regulatory asset or regulatory liability and will be reflected in future rates charged to customers.

As indicated in Note 1 - "Summary of Significant Accounting Policies - Income Taxes", KU's regulated operations' accounting for income taxes is impacted by rate regulation. Therefore, reductions in accumulated deferred income tax balances due to the reduction in the U.S. federal corporate income tax rate to 21% under the provisions of the TCJA may result in amounts previously collected from utility customers for these deferred taxes to be refundable to such customers over a period of time. The TCJA includes provisions that stipulate how these excess deferred taxes are to be passed back to customers for certain accelerated tax depreciation benefits. Potential refunds of other deferred taxes will be determined by KU's regulators. The Balance Sheet at December 31, 2017 reflects a net increase of $634 million to KU's regulatory liabilities as a result of the TCJA.

The measurement period ends at the earlier of the time the company finalizes its accounting for the impact of the TCJA or one year.

KU has completed or made reasonable estimates of the effects of the TCJA and reflected these amounts in its December 31, 2017 financial statements. KU continues to evaluate the application of the TCJA and has made certain assumptions concerning the application of various components of the law in the calculation of 2017 income tax expense. The current and deferred components of the income tax expense calculations that KU considers provisional within the meaning of the SEC guidance due to uncertainty either with respect to the technical application of the law or the quantification of the impact of the law include (but are not limited to) tax depreciation. KU believes that classification of these items as provisional is appropriate. KU has accounted for these items based on its interpretation of the TCJA.

Further interpretive guidance on the TCJA from the IRS, Treasury, the Joint Committee on Taxation through its "Blue Book" or from Congress in the form of Technical Corrections may differ from KU's interpretation of the TCJA.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes and the tax effects of net operating loss and tax credit carryforwards. Net deferred tax assets have been recognized based on management's estimates of future taxable income.

KU's provision for deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the KPSC, VSCC and the FERC. The difference in the provision for deferred income taxes for regulated assets and liabilities and the amount that otherwise would be recorded under GAAP is deferred and included in "Regulatory assets" or "Regulatory liabilities" on the Balance Sheets.

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Significant components of KU's deferred income tax assets and liabilities at December 31 were as follows:

	2017 (a)	2016
Deferred Tax Assets		
Federal loss carryforwards	$ 13	$ 79
Contribution in aid of construction	6	11
Regulatory liabilities	16	26
Deferred investment tax credits	24	37
Income taxes due to customers (b)	163	-
Other	9	11
Total deferred tax assets	231	164
Deferred Tax Liabilities		
Plant - net (b)	882	1,280
Regulatory assets	21	37
Accrued pension costs	17	12
Other	2	5
Total deferred tax liabilities	922	1,334
Net deferred tax liability	$ 691	$ 1,170

(a) Deferred tax assets and liabilities at December 31, 2017 reflect the U.S. federal corporate income tax rate reduction from 35% to 21% enacted by the TCJA.
(b) The impact on net deferred tax liabilities as a result of the U.S. federal tax rate reduction enacted by the TCJA is primarily related to plant (net of net operating losses) and resulted in a regulatory liability for income taxes due to customers, the deferred tax impact of which is reflected as a deferred tax asset.

KU expects to have adequate levels of taxable income to realize its recorded deferred income tax assets.

At December 31, 2017, KU had $61 million of federal net operating loss carryforwards that expire in 2035 and $6 million of federal credit carryforwards that expire from 2034 to 2037.

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Details of the components of income tax expense and a reconciliation of federal income taxes derived from statutory tax rates applied to "Income Before Income Taxes" to income taxes for reporting purposes as of and for the year ended were:

	2017	2016
Income Tax Expense (Benefit)		
Current - Federal	$ -	$ 31
Current - State	7	5
Total Current Expense	7	36
Deferred - Federal	138	131
Deferred - State	16	19
Total Deferred Expense, excluding benefits of operating loss carryforwards	154	150
Investment tax credit, net - Federal	(2)	(2)
Tax benefit of operating loss carryforwards		
Deferred - Federal	-	(21)
Total Tax Benefit of Operating Loss Carryforwards	-	(21)
Total income tax expense	$ 159	$ 163
Total income tax expense - Federal	$ 136	$ 139
Total income tax expense - State	23	24
Total income tax expense (a)	$ 159	$ 163

(a) Excludes deferred federal and state tax expense (benefit) recorded to OCI of less than $1 million in 2017 and $(1) million in 2016.

	2017	2016
Reconciliation of Income Taxes		
Federal income tax on Income Before Income Taxes at statutory tax rate - 35%	$ 120	$ 115
Increase (decrease) due to:		
State income taxes, net of federal income tax benefit	13	12
Amortization of investment tax credit	(1)	(1)
Other	(1)	-
Total increase	11	11
Total income tax expense	$ 131	$ 126
Effective income tax rate	38.1%	38.3%

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For the years ended December 31, 2017 and 2016, KU incurred expenses of $32 million and $30 million related to taxes, other than income. Taxes, other than income were comprised primarily of property taxes.

Unrecognized Tax Benefits

KU's income tax provision is calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if KU filed a separate return. Based on this tax sharing agreement, KU indirectly files tax returns in two major tax jurisdictions. At December 31, 2017, these jurisdictions, as well as the tax years that are no longer subject to examination, were as follows:

U.S. (federal)	2013 and prior
Kentucky (state)	2012 and prior

4. Utility Rate Regulation

Regulatory Assets and Liabilities

KU reflects the effects of regulatory actions in the financial statements for its cost-based rate-regulated utility operations. Regulatory assets and liabilities are classified as current if, upon initial recognition, the entire amount related to that item will be recovered or refunded within a year of the balance sheet date.

KU is subject to the jurisdiction of the KPSC, FERC and VSCC.

KU's Kentucky base rates are calculated based on a return on capitalization (common equity, long-term debt and short-term debt) including adjustments for certain net investments and costs recovered separately through other means. As such, KU generally earns a return on regulatory assets.

As a result of purchase accounting requirements, certain fair value amounts related to contracts that had favorable or unfavorable terms relative to market were recorded on the Balance Sheets with an offsetting regulatory asset or liability. KU recovers in customer rates the cost of power purchases. As a result, management believes the regulatory assets and liabilities created to offset the fair value amounts at LKE's acquisition date meet the recognition criteria established by existing accounting guidance and eliminate any rate-making impact of the fair value adjustments. KU's customer rates continue to reflect the original contracted prices for remaining contracts.

KU's Virginia base rates are calculated based on a return on rate base (net utility plant plus working capital less deferred taxes and miscellaneous deductions). All regulatory assets and liabilities, except the levelized fuel factor, are excluded from the return on rate base utilized in the calculation of Virginia base rates. Therefore, no return is earned on the related assets.

KU's rates to municipal customers for wholesale requirements are calculated based on annual updates to a rate formula that utilizes a return on rate base (net utility plant plus working capital less deferred taxes and miscellaneous deductions). All regulatory assets and liabilities, except regulatory assets recorded for AROs related to certain CCR impoundments, are excluded from the return on rate base utilized in the development of

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municipal rates. Therefore, no return is earned on the related assets.

The following table provides information about the regulatory assets and liabilities of cost-based rate-regulated utility operations at December 31:

	2017	2016
Current Regulatory Assets:		
Generation formula rate	$ 6	$ 11
Total current regulatory assets	$ 6	$ 11
Noncurrent Regulatory Assets:		
Defined benefit plans	$ 142	$ 152
Storm costs	15	22
Unamortized loss on debt	9	9
Terminated interest rate swaps	38	41
AROs	173	141
Other	7	9
Total noncurrent regulatory assets	$ 384	$ 374
Current Regulatory Liabilities:		
Fuel adjustment clause	$ 3	$ 9
Other	3	4
Total current regulatory liabilities	$ 6	$ 13
Noncurrent Regulatory Liabilities:		
Net deferred tax assets (a)	$ 633	$ -
Accumulated cost of removal of utility plant	395	395
Power purchase agreement - OVEC (b)	21	23
Defined benefit plans	27	23
Terminated interest rate swaps	37	39
Other	4	-
Total noncurrent regulatory liabilities	$ 1,117	$ 480

(a) Primarily relates to excess deferred taxes recorded as a result of the TCJA, which lowered the federal corporate income tax rate effective January 1, 2018 requiring deferred tax balances and the associated regulatory liabilities to be remeasured as of December 31, 2017.
(b) This liability was recorded as an offset to an intangible asset that was recorded at fair value upon the acquisition of LKE by PPL.

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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

Defined benefit plan regulatory assets and liabilities represent prior service costs and net actuarial gains and losses that will be recovered in defined benefit plans expense through future base rates based upon established regulatory practices and, generally, are amortized over the average remaining service lives of plan participants. These regulatory assets and liabilities are adjusted at least annually or whenever the funded status of defined benefit plans is remeasured. Of the regulatory asset and liability balances recorded, costs of $12 million are expected to be amortized into net periodic defined benefit costs in 2018 in accordance with KU's pension accounting policy.

As a result of the 2014 Kentucky rate case settlement that became effective July 1, 2015, the difference between pension cost calculated in accordance with LG&E's pension accounting policy and pension cost calculated using a 15-year amortization period for actuarial gains and losses is recorded as a regulatory asset. As of December 31, 2017 and 2016, the balances were $15 million and $9 million. Of the costs expected to be amortized into net periodic defined benefit costs in 2018, $6 million is expected to be recorded as a regulatory asset in 2018.

Storm Costs

KU has the ability to request from the KPSC and VSCC, as applicable, the authority to treat expenses related to specific extraordinary storms as a regulatory asset and defer such costs for regulatory accounting and reporting purposes. Once such authority is granted, KU can request recovery of those expenses in a base rate case and begin amortizing the costs when recovery starts. KU's regulatory assets for storm costs are being amortized through various dates ending in 2020.

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 2042.

Regulatory Liability Associated with Net Deferred Taxes

Regulatory liabilities associated with net deferred taxes represent the future revenue impact from the adjustment of deferred income taxes required primarily for excess deferred taxes and unamortized investment tax credits. At December 31, 2017, excess deferred taxes recorded as a result of the TCJA were $634 million, which includes the gross-up associated with the excess deferred taxes.

Environmental Cost Recovery

Kentucky law permits KU to recover the costs, including a return of operating expenses and a return of and on capital invested, of complying with the Clean Air Act and those federal, state or local environmental requirements, which apply to coal combustion wastes and by-products from coal-fired electricity 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. In December 2017, the KPSC issued orders continuing the use of an authorized return on equity of 9.7% for all existing approved ECR plans and projects. 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 typically recovered within 12 months.

Fuel Adjustment Clauses

KU's retail electric rates contain a fuel adjustment clause, whereby variances in the cost of fuel to generate electricity, including transportation costs, from the costs embedded in base rates are adjusted in KU's rates. The KPSC requires public hearings at six-month intervals to examine past fuel adjustments and at two-year intervals to review past operations of the fuel adjustment clause and, to the extent appropriate, reestablish the fuel charge included in base rates. The regulatory assets or liabilities represent the amounts that have been under- or over-recovered due to timing or adjustments to the mechanism and are typically recovered within 12 months.

KU also employs a levelized fuel factor mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The Virginia levelized fuel factor allows fuel recovery based on projected fuel costs for the coming year plus an adjustment for any under- or over-recovery of fuel expenses from the prior year. The regulatory assets or liabilities represent the amounts that have been under- or over-recovered due to timing or adjustments to the mechanism and are typically recovered within 12 months.

Demand Side Management

KU's DSM programs consist of energy efficiency programs, intended to reduce peak demand and delay investment in additional power plant construction, provide customers with tools and information to become better managers of their energy usage and prepare for potential future legislation governing energy efficiency. KU's rates contain a DSM provision, which includes a rate recovery mechanism that provides for concurrent recovery of DSM costs and incentives, and allows for the recovery of DSM revenues from lost sales associated with the DSM programs. Additionally, KU earns an approved return on equity for capital expenditures associated with the residential and commercial load management and demand conservation programs. The cost of DSM programs is assigned only to the class or classes of customers that benefit from the programs. These amounts are included in other current regulatory assets or other current regulatory liabilities above.

AROs

As discussed in Note 1, all ARO accretion and depreciation expenses are reclassified as a regulatory asset. ARO regulatory assets associated with certain CCR projects are amortized to expense in accordance with regulatory approvals. For other AROs, at the time of retirement, the related ARO regulatory asset is offset against the associated cost of removal regulatory liability, PP&E and ARO liability.

Power Purchase Agreement - OVEC

As a result of purchase accounting associated with PPL's acquisition of LKE, the fair value of the OVEC power purchase agreement was recorded on the Balance Sheets 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. See Notes 1, 10 and 14 for additional discussion of the power purchase agreement.

Terminated Interest Rate Swaps

Net realized gains and losses on all interest rate swaps are probable of recovery through regulated rates; as such, any gains and losses on these derivatives are included in regulatory assets or liabilities and are primarily recognized in "Interest Expense" on the Statements of Income over the life of the associated debt.

Plant Outage Costs

The Stipulation to the 2016 Kentucky rate case that became effective July 1, 2017 provided for the normalization of expenses associated with plant outages using an eight-year average. The eight-year average is comprised of four historical years' and four forecasted years' expenses. Plant outage expenses that are greater or less than the eight-year average will be collected from or returned to customers, through future base rates. These amounts are included in other current regulatory assets or other current regulatory liabilities above.

Generation Formula Rates

KU provides wholesale requirements service to its municipal customers and bills for this service pursuant to a FERC approved generation formula rate. Under this formula, rates are put into effect in July of each year utilizing a return on rate base calculation and actual expenses from the preceding year. The regulatory asset represents the difference between the revenue requirement in effect for the preceding year and actual expenditures incurred for the current year.

Regulatory Matters

Rate Case Proceedings

In November 2016, KU filed a request with the KPSC for an increase in annual base electricity rates. The application included requests for CPCNs for implementing an Advanced Metering System program and a Distribution Automation program.

In April and May 2017, KU along with all intervening parties to the proceeding, filed with the KPSC, stipulation and recommendation agreements (stipulations) resolving all issues with the parties. Among other things, the proposed stipulations provided for increased annual revenue requirements associated with base electricity rates of $55 million, reflecting a return on equity of 9.75%, the withdrawal of the request for a CPCN for the Advanced Metering System and other changes to the revenue requirements, which dealt primarily with the timing of cost recovery, including depreciation rates.

In June 2017, the KPSC issued orders approving, with certain modifications, the proposed stipulations filed in April and May 2017. The orders modified the stipulations to provide for increased annual revenue requirements associated with base electricity rates of $52 million and incorporated an authorized return on equity of 9.7%. Consistent with the stipulations, the orders approved the request for implementing a Distribution Automation program and its withdrawal of a request for a CPCN for the Advanced Metering System program. The orders also approved new depreciation rates that resulted in higher depreciation of approximately $11 million in 2017, exclusive of net additions to PP&E. The orders resulted in a base electricity rate increase of 3.2%. The new base rates and all elements of the orders became effective July 1, 2017. On June 23, 2017, the KPSC issued orders establishing an authorized return on equity of 9.7% for all existing approved ECR plans and projects, replacing the prior authorized return on equity levels of 9.8% for CCR projects and 10% for all other ECR approved projects, effective with bills issued in August 2017. The annual impact of the new authorized return for ECR projects is not expected to be significant.

CPCN Filing

On January 10, 2018, KU filed an application for a CPCN with the KPSC requesting approval for implementing Advanced Metering Systems across its Kentucky service territories. The full Advanced Metering Systems deployment is expected to be completed in 2021 with estimated capital costs of $155 million. The full deployment will also result in incremental operation and maintenance costs during the deployment phase of $17 million.

TCJA Impact on Rates

On December 21, 2017, Kentucky Industrial Utility Customers, Inc. submitted a complaint with the KPSC against KU and other utility companies in Kentucky, alleging that their respective rates would no longer be fair, just and reasonable following the enactment of the TCJA reducing the federal corporate tax rate from 35% to 21%. The complaint requested the KPSC to issue an order requiring KU to begin deferring, as of January 1, 2018, the revenue requirement effect of all income tax expense savings resulting from the federal corporate income tax reduction, including the amortization of excess deferred income taxes by recording those savings in a regulatory liability account and establishing a process by which the federal corporate income tax savings will be passed back to customers.

On December 27, 2017, as a result of the complaint, the KPSC ordered KU to satisfy or address the complaint and commence recording regulatory liabilities to reflect the reduction in the federal corporate tax rate to 21% and the associated savings in excess deferred taxes on an interim basis until utility rates are adjusted to reflect the federal tax savings.

On January 8, 2018, KU responded to the complaint, denying certain claims in the complaint but concurring that the TCJA will result in savings for its customers. KU stated in its response that the company recorded regulatory liabilities as of December 31, 2017 to reflect the reduction in the federal corporate tax rate and the associated savings in excess deferred taxes and will make changes to its ECR and DSM rate mechanisms to begin providing the applicable savings to customers. KU also offered to establish a new bill credit mechanism effective with the April 2018 billing cycle to begin distributing the tax savings associated with base rates to customers.

On January 29, 2018, KU reached a settlement agreement to commence returning savings related to the TCJA to its customers. The savings will be distributed through its ECR and DSM rate mechanisms beginning in March 2018 and through a new bill credit mechanism from April 1, 2018 through April 30, 2019. The estimated impact of the rate reduction represents approximately $91 million in electricity revenues for the period January 2018 through April 2019. Ongoing tax savings are expected to also be addressed in KU's next Kentucky base rate case. KU indicated its intent to file an application for base rate changes during 2018 to be effective during spring 2019. The settlement agreement is subject to review and approval by the KPSC. An order in the proceeding may occur during the first quarter of 2018.

Additionally, on January 8, 2018, the VSCC ordered KU, as well as other utilities in Virginia, to accrue regulatory liabilities reflecting the Virginia jurisdictional revenue requirement impacts of the reduced federal corporate tax rate.

The FERC has not issued any guidance on the effect on rates of the TCJA.

KU cannot predict the outcome of these proceedings.

5. Financing Activities

Credit Arrangements and Short-term Debt

KU maintains credit facilities to enhance liquidity, provide credit support and provide a backstop to its commercial paper program. The amounts borrowed below are recorded as "Short-term debt" on the Balance Sheets. The following credit facilities were in place at December 31:

	2017			2016		
	Syndicated Credit Facility	Letter of Credit Facility	Total Credit Facilities	Syndicated Credit Facility	Letter of Credit Facility	Total Credit Facilities
Expiration Date	Jan-2022	Oct-2020		Dec-2020	Oct-2017	
Capacity	$ 400	$ 198	$ 598	$ 400	$ 198	$ 598
Commercial Paper Issuances	$ 45	$ -	$ 45	$ 16	$ -	$ 16
Letter of Credit Issuances	$ -	$ 198	$ 198	$ -	$ 198	$ 198
Unused Capacity	$ 355	$ -	$ 355	$ 384	$ -	$ 384

KU pays customary fees under its facilities and borrowings generally bear interest at LIBOR-based rates plus an applicable margin. The facilities contain a financial covenant requiring debt to total capitalization not to exceed 70% as calculated in accordance with the facility and other customary covenants. Additionally, as it relates to

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the syndicated credit facility and subject to certain conditions, KU may request up to a $100 million increase in its facility's capacity. KU's letter of credit facility agreement allows for certain payments under the letter of credit facility to be converted to loans rather than requiring immediate payment.

In January 2018, the expiration date for KU’s syndicated credit facility expiring in January 2022 was extended to January 2023.

KU maintains a commercial paper program to provide an additional financing source to fund short-term liquidity needs, as necessary. Commercial paper issuances, included in "Short-term debt" on the Balance Sheets, are supported by KU’s syndicated credit facility. The following commercial paper program was in place at December 31:

	2017		2016	
Weighted - Average Interest Rate		1.97%		0.87%
Capacity	$	350	$	350
Commercial Paper Issuances	$	45	$	16
Unused Capacity	$	305	$	334

See Note 11 for discussion of intercompany borrowings.

Long-term Debt

	December 31, 2017	December 31, 2016
First Mortgage Bonds		
Total Long-term Debt Before Adjustments	$ 2,351	$ 2,351
	2,351	2,351
Other		
Fair market value adjustments	-	-
Unamortized discount	(9)	(9)
Unamortized debt issuance costs	(14)	(15)
Total Long-term Debt	2,328	2,327
Less current portion of Long-term Debt	-	-
Total Long-term Debt, noncurrent	$ 2,328	$ 2,327
Weighted-Average Rate (a)	3.91%	3.45%
Maturities (a)	2019 - 2045	2017 - 2045

(a) The table reflects principal maturities only, based on stated maturities or earlier put dates, and the weighted-average rates as of December 31, 2017.

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KU's first mortgage bonds are secured by the lien of the KU 2010 Mortgage Indenture which creates a lien, subject to certain exceptions and exclusions, on substantially all of KU's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity. The aggregate carrying value of the property subject to the lien was $6.0 billion and $5.8 billion at December 31, 2017 and 2016.

The first mortgage bonds were issued to the respective trustees of tax-exempt revenue bonds to secure obligations to make payments with respect to each series of bonds. The first mortgage bonds were issued in the same principal amounts, contain payment and redemption provisions that correspond to and bear the same interest rate as such tax-exempt revenue bonds. The related tax-exempt revenue bonds were issued by various governmental entities, principally counties in Kentucky, on behalf of KU. The related revenue bond documents allow KU to convert the interest rate mode on the bonds from time to time to a commercial paper rate, daily rate, weekly rate, term rate of at least one year or, in some cases, an auction rate or a LIBOR index rate.

At December 31, 2017, the aggregate tax-exempt revenue bonds issued on behalf of KU that were in a term rate mode totaled $123 million. At December 31, 2017, the aggregate tax-exempt revenue bonds issued on behalf of KU that were in a variable rate mode totaled $228 million. These variable rate tax-exempt revenue bonds are subject to tender for purchase by KU at the option of the holder and to mandatory tender for purchase by KU upon the occurrence of certain events.

None of the outstanding debt securities noted above have sinking fund requirements. The aggregate maturities of long-term debt, based on stated maturities or earlier put dates, for the periods 2018 through 2022 and thereafter are as follows:

2018	$	-
2019		96
2020		500
2021		-
2022		-
Thereafter		1,755
Total	$	2,351

Legal Separateness

The subsidiaries of PPL are separate legal entities. PPL's subsidiaries are not liable for the debts of PPL. Accordingly, creditors of PPL may not satisfy their debts from the assets of PPL's subsidiaries absent a specific contractual undertaking by a subsidiary to pay PPL's creditors or as required by applicable law or regulation. Similarly, PPL is not liable for the debts of its subsidiaries, nor are its subsidiaries liable for the debts of one another. Accordingly, creditors of PPL's subsidiaries may not satisfy their debts from the assets of PPL or its other subsidiaries absent a specific contractual undertaking by PPL or its other subsidiaries to pay the creditors or as required by applicable law or regulation.

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Similarly, the subsidiaries of LKE are each separate legal entities. These subsidiaries are not liable for the debts of LKE. Accordingly, creditors of LKE may not satisfy their debts from the assets of its subsidiaries absent a specific contractual undertaking by a subsidiary to pay the creditors or as required by applicable law or regulation. Similarly, LKE is not liable for the debts of its subsidiaries, nor are its subsidiaries liable for the debts of one another. Accordingly, creditors of its subsidiaries may not satisfy their debts from the assets of LKE (or its other subsidiaries) absent a specific contractual undertaking by that parent or other subsidiary to pay such creditors or as required by applicable law or regulation.

Distributions and Related Restrictions

LKE primarily relies on dividends from its subsidiaries to fund its distributions to PPL. KU is subject to Section 305(a) of the Federal Power Act, which makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in capital account." The meaning of this limitation has never been clarified under the Federal Power Act. KU believes, however, that this statutory restriction, as applied to its circumstances, would not be construed or applied by the FERC to prohibit the payment from retained earnings of dividends that are not excessive and are for lawful and legitimate business purposes. In February 2012, KU petitioned the FERC requesting authorization to pay dividends in the future based on retained earnings balances calculated without giving effect to the impact of purchase accounting adjustments for the acquisition of LKE by PPL. In May 2012, the FERC approved the petition with the further condition that KU may not pay dividends if such payment would cause its adjusted equity ratio to fall below 30% of total capitalization. Accordingly, at December 31, 2017, net assets of $1.6 billion were restricted for purposes of paying dividends to LKE, and net assets of $1.7 billion were available for payment of dividends to LKE. KU believes it will not be required to change its current dividend practice as a result of the foregoing requirement. In addition, under Virginia law, KU is prohibited from making loans to affiliates without the prior approval of the VSCC. There are no comparable statutes under Kentucky law applicable to KU. However, orders from the KPSC require KU to obtain prior consent or approval before lending amounts to PPL or LKE.

6. Acquisitions, Development and Divestitures

From time to time, KU evaluates opportunities for potential acquisitions, divestitures and development projects. Development projects are reexamined based on market conditions and other factors to determine whether to proceed with, modify or terminate the projects. Any resulting transactions may impact future financial results.

Development

<u>Capacity Needs</u>

As a result of environmental requirements and energy efficiency measures, KU anticipates retiring two older coal-fired electricity generating units at the E.W. Brown plant in 2019 with a combined summer rating capacity of 272 MW.

In December 2014, a final order was issued by the KPSC approving KU's and LG&E's request to construct a solar generation facility at the E.W. Brown facility. The jointly-owned 10 MW facility was placed into commercial operation in June 2016 at a cost of $25 million.

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7. Leases

KU has entered into various agreements for the lease of office space, vehicles, land and other equipment.

Rent - Operating Leases

Rent expense for operating leases was $11 million for the years ended December 31, 2017 and 2016.

Total future minimum rental payments for all operating leases are estimated to be:

2018	$	10
2019		8
2020		6
2021		5
2022		4
Thereafter		8
Total	$	41

8. Retirement and Postemployment Benefits

Defined Benefits

KU does not directly sponsor any defined benefit plans. KU is allocated a portion of the funded status and costs of the plan sponsored by LKE based on its participation in the plan, which management believes are reasonable. The LKE plan was 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 majority of employees are eligible for certain health care and life insurance benefits upon retirement through a contributory plan sponsored by LKE. Postretirement health benefits may be paid from 401(h) accounts established as part of the LKE plan within the PPL Services Corporation Master Trust, funded VEBA trusts and company funds.

The amounts recognized in KU’s regulatory assets and liabilities based on KU’s participation in LKE’s pension plan and postretirement plan at December 31 were as follows:

	Pension Benefits				Other Postretirement Benefits			
	2017		2016		2017		2016	
Prior service cost	$	3	$	3	$	4	$	1
Net actuarial (gain) loss		124		140		(31)		(24)
Total	$	127	$	143	$	(27)	$	(23)

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As a result of the 2014 Kentucky rate case settlement that became effective July 1, 2015, the difference between actuarial (gain)/loss calculated in accordance with KU's pension accounting policy and the actuarial (gain)/loss calculated using a 15 year amortization period is recorded as a regulatory asset. This difference was $14 million and $9 million as of December 31, 2017 and 2016.

For KU’s participation in LKE’s pension plan, the estimated amount to be amortized from regulatory assets into net periodic defined benefit costs in 2018 is $12 million ($1 million amortization of prior service cost and $11 million amortization of actuarial loss). For KU’s participation in LKE’s other postretirement plan, the estimated amount to be amortized from regulatory liabilities into net periodic defined benefit costs in 2018 is less than $1 million (amortization of prior service cost).

Of the costs expected to be amortized into net periodic benefit costs for pension benefits in 2018, $4 million is expected to be recorded as a regulatory asset for the difference between net periodic costs under the pension accounting policy and using a 15 year amortization period for gains and losses.

Allocations to KU for net periodic defined benefit costs charged to operating expense or regulatory assets, excluding amounts charged to construction work in progress and other non-expense accounts, for pension benefits were $4 million and $5 million in 2017 and 2016. Net periodic defined benefit costs charged to operating expense, excluding amounts charged to construction work in progress and other non-expense accounts, for other postretirement benefits were $1 million and $2 million in 2017 and 2016. These allocations are based on participation in those plans, which management believes are reasonable.

Of the costs charged to operating expense or regulatory assets, excluding amounts charged to construction and other non-expense accounts, $2 million was recorded as regulatory assets during 2017 and 2016 representing the difference between net periodic defined benefit costs under the pension accounting policy and using a 15 year amortization period for gains and losses.

LKE utilized the mortality tables issued by the Society of Actuaries in October 2014 (RP-2014 base tables with collar and factor adjustments, where applicable) for its defined benefit pension and other postretirement benefit plans. In addition, LKE updated the basis for estimating projected mortality improvements and selected the IRS BB-2D two-dimensional improvement scales on a generational basis for its defined benefit pension and other postretirement benefit plans. In 2017, LKE updated to the MP-2017 mortality improvement scale from 2006 on a generational basis. This new mortality assumption reflects the expectation of lower ongoing improvements in life expectancies.

KU is allocated a portion of the funded status and costs of certain defined benefit plans sponsored by LKE. KU is also allocated costs of defined benefit plans from LKS for defined benefit plans sponsored by LKE. See Note 11 for additional information on costs allocated to KU from LKS. These allocations are based on KU’s participation in those plans, which management believes are reasonable. The actuarially determined obligations of current active employees and retired employees of KU are used as a basis to allocate total plan activity, including active and retiree costs and obligations. Allocations to KU for pension benefits resulted in a liability of $36 million and $62 million at December 31, 2017 and 2016. Allocations to KU for other postretirement benefits resulted in a liability of $32 million and $40 million at December 31, 2017 and 2016.

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Plan Assets - Pension Plans

The pension plan sponsored by LKE is invested in the PPL Services Corporation Master Trust (the Master Trust) that also includes 401(h) accounts that are restricted for certain other postretirement benefit obligations of PPL and LKE. The investment strategy for the Master Trust is to achieve a risk-adjusted return on a mix of assets that, in combination with KU's funding policy, will ensure that sufficient assets are available to provide long-term growth and liquidity for benefit payments, while also managing the duration of the assets to complement the duration of the liabilities. The Master Trust benefits from a wide diversification of asset types, investment fund strategies and external investment fund managers, and therefore has no significant concentration of risk.

The investment policy of the Master Trust outlines investment objectives and defines the responsibilities of the EBPB, external investment managers, investment advisor and trustee and custodian. The investment policy is 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: 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, generally with long durations, and derivative positions. 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. EBPB investment guidelines as of the end of 2017 are presented below.

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The asset allocation for the trust and the target allocation by portfolio at December 31 are as follows:

	Percentage of Trust Assets 2017 (a)	2017 Target Asset Allocation (a) Weighted Average
Growth Portfolio	**56%**	**55%**
Equity securities	32%	
Debt securities (b)	14%	
Alternative investments	10%	
Immunizing Portfolio	**43%**	**43%**
Debt securities (b)	39%	
Derivatives	4%	
Liquidity Portfolio	**1%**	**2%**
Total	100%	100%

	Percentage of Trust Assets 2016
Growth Portfolio	**52%**
Equity securities	30%
Debt securities (b)	12%
Alternative investments	10%
Immunizing Portfolio	**46%**
Debt securities (b)	43%
Derivatives	3%
Liquidity Portfolio	**2%**
Total	100%

(a) Allocations exclude consideration of a group annuity contract held by the LG&E and KU Retirement Plan.
(b) Includes commingled debt funds, which are treated as debt securities for asset allocation purposes.

LKE's pension plan assets are invested solely in the Master Trust, which is fully disclosed below. The fair value of LKE's plans' assets of $1.4 and $1.3 billion at December 31, 2017 and 2016 represents an interest of approximately 40% and 41% in the Master Trust.

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The fair value of net assets in the PPL Services Corporation Master Trust by asset class and level within the fair value hierarchy as of December 31 was:

	2017			
	Total	Level 1	Level 2	Level 3
Cash and cash equivalents	$ 301	$ 301	$ -	$ -
Equity securities:				
U.S. Equity	229	229	-	-
U.S. Equity fund measured at NAV (a)	364	-	-	-
International equity fund at NAV (a)	538	-	-	-
Commingled debt measured at NAV (a)	611	-	-	-
Debt securities:				
U.S. Treasury and U.S. government sponsored agency	186	186	-	-
Corporate	883	-	870	13
Other	10	-	10	-
Alternative investments:				
Real estate measured at NAV (a)	109	-	-	-
Private equity measured at NAV (a)	80	-	-	-
Hedge funds measured at NAV (a)	175	-	-	-
Derivatives:				
Interest rate swaps and swaptions	50	-	50	-
Other	1	-	1	-
Insurance contracts	24	-	-	24
PPL Services Corporation Master Trust assets, at fair value	$ 3,561	$ 716	$ 931	$ 37
Receivables and payables, net (b)	72			
401(h) accounts restricted for other postretirement benefit obligations	(145)			
Total PPL Services Corporation Master Trust pension assets	$ 3,488			

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	2016			
	Total	**Level 1**	**Level 2**	**Level 3**
Cash and cash equivalents	$ 181	$ 181	$ -	$ -
Equity securities:				
U.S. Equity	152	152	-	-
U.S. Equity fund measured at NAV (a)	272	-	-	-
International equity fund at NAV (a)	551	-	-	-
Commingled debt measured at NAV (a)	546	-	-	-
Debt securities:				
U.S. Treasury and U.S. government sponsored agency	381	381	-	-
Corporate	850	-	837	13
Other	8	-	8	-
Alternative investments:				
Real estate measured at NAV (a)	102	-	-	-
Private equity measured at NAV (a)	80	-	-	-
Hedge funds measured at NAV (a)	167	-	-	-
Derivatives:				
Interest rate swaps and swaptions	61	-	61	-
Other	3	-	3	-
Insurance contracts	27	-	-	27
PPL Services Corporation Master Trust assets, at fair value	$ 3,381	$ 714	$ 909	$ 40
Receivables and payables, net (b)	(15)			
401(h) accounts restricted for other postretirement benefit obligations	(123)			
Total PPL Services Corporation Master Trust pension assets	$ 3,243			

(a) In accordance with accounting guidance certain investments that are measured at fair value using the net asset value per share (NAV), or its equivalent practical expedient, have not been classified in the fair value hierarchy. The fair value amounts presented in the table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the statement of financial position.
(b) Receivables and payables represent amounts for investments sold/purchased but not yet settled along with interest and dividends earned but not yet received.

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A reconciliation of the Master Trust assets classified as Level 3 at December 31, 2017 is as follows:

	Corporate debt	Insurance contracts	Total
Balance at beginning of period	$ 13	$ 27	$ 40
Actual return on plan assets			
Relating to assets still held			
at the reporting date	-	1	1
Purchases, sales and settlements	-	(4)	(4)
Balance at end of period	$ 13	$ 24	$ 37

A reconciliation of the Master Trust assets classified as Level 3 at December 31, 2016 is as follows:

	Corporate debt	Insurance contracts	Total
Balance at beginning of period	$ 10	$ 32	$ 42
Actual return on plan assets			
Relating to assets still held			
at the reporting date	-	1	1
Purchases, sales and settlements	3	(6)	(3)
Balance at end of period	$ 13	$ 27	$ 40

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 equity and debt funds are categorized as equity securities. Investments in commingled equity funds include funds that invest in U.S. and international equity securities. Investments in commingled debt funds include funds that invest in a diversified portfolio of emerging market debt obligations, as well as funds that invest in investment grade long-duration fixed-income securities.

The fair value measurements of debt securities are generally based on evaluations that reflect observable market information, such as actual trade information for identical securities or for similar securities, adjusted for observable differences. The fair value of debt securities is generally measured using a market approach, including the use of pricing models which incorporate observable inputs. Common inputs include benchmark yields, relevant trade data, 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 payment data, future predicted cash flows, collateral performance and new

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issue data. For the Master Trust, these securities represent investments in securities issued by U.S. Treasury and U.S. government sponsored agencies; investments securitized by residential mortgages, auto loans, credit cards and other pooled loans; investments in investment grade and non-investment grade bonds issued by U.S. companies across several industries; investments in debt securities issued by foreign governments and corporations.

Investments in real estate represent an investment in a partnership whose purpose is to manage investments in core U.S. real estate properties diversified geographically and across major property types (e.g., office, industrial, retail, etc.). The manager is focused on properties with high occupancy rates with quality tenants. This results in a focus on high income and stable cash flows with appreciation being a secondary factor. Core real estate generally has a lower degree of leverage when compared with more speculative real estate investing strategies. The partnership has limitations on the amounts that may be redeemed based on available cash to fund redemptions. Additionally, the general partner may decline to accept redemptions when necessary to avoid adverse consequences for the partnership, including legal and tax implications, among others. The fair value of the investment is based upon a partnership unit value.

Investments in private equity represent interests in partnerships in multiple early-stage venture capital funds and private equity fund of funds that use a number of diverse investment strategies. The partnerships have limited lives of at least 10 years, after which liquidating distributions will be received. Prior to the end of each partnership's life, the investment cannot be redeemed with the partnership; however, the interest may be sold to other parties, subject to the general partner's approval. The Master Trust has unfunded commitments of $28 million that may be required during the lives of the partnerships. Fair value is based on an ownership interest in partners' capital to which a proportionate share of net assets is attributed.

Investments in hedge funds represent investments in a fund of hedge funds. Hedge funds seek a return utilizing a number of diverse investment strategies. The strategies, when combined, aim to reduce volatility and risk while attempting to deliver positive returns under most market conditions. Major investment strategies for the fund of hedge funds include long/short equity, tactical trading, event driven, and relative value. Shares may be redeemed within 45 days with prior written notice. The fund is subject to short term lockups and other restrictions. The fair value for the fund has been estimated using the net asset value per share.

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 primarily represent investments in interest rate swaps and swaptions (the option to enter into an interest rate swap), which are valued based on the swap details, such as swap curves, notional amount, index and term of index, reset frequency, volatility and payer/receiver credit ratings.

Insurance contracts, classified as Level 3, represent an investment in an immediate participation guaranteed group annuity contract. The fair value is based on contract value, which represents cost plus interest income less distributions for benefit payments and administrative expenses.

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Plan Assets - Other Postretirement Benefit Plans

	Percentage of Plan Assets 2017	2017 Target Asset Allocation Weighted Average
Asset Class		
U.S. Equity securities	47%	45%
Debt securities (a)	49%	50%
Cash and cash equivalents (b)	4%	5%
Total	100%	100%

	Percentage of Plan Assets 2016
Asset Class	
U.S. Equity securities	48%
Debt securities (a)	50%
Cash and cash equivalents (b)	2%
Total	100%

(a) Includes commingled debt funds and debt securities.
(b) Includes money market funds.

LKE's other postretirement benefit plan is invested primarily in a 401(h) account, as disclosed in the PPL Services Corporation Master Trust, with insignificant amounts invested in money market funds within VEBA trusts for liquidity.

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The fair value of assets in the U.S. other postretirement benefit plans by asset class and level within the fair value hierarchy was:

	2017			
	Total	Level 1	Level 2	Level 3
Money market funds	$ 10	$ 10	$ -	$ -
U.S. Equity securities:				
Large-cap equity fund measure at NAV (a)	123	-	-	-
Commingled debt measured at NAV (a)	96	-	-	-
Debt securities:				
Corporate bonds	30	-	30	-
Total VEBA trust assets, at fair value	$ 259	$ 10	$ 30	$ -
Receivables and payables, net (b)	1			
401(h) account assets	145			
Total other postretirement benefit plan assets	$ 405			

	2016			
	Total	Level 1	Level 2	Level 3
Money market funds	$ 5	$ 5	$ -	$ -
U.S. Equity securities:				
Large-cap equity fund measure at NAV (a)	123	-	-	-
Commingled debt measured at NAV (a)	114	-	-	-
Debt securities:				
Municipalities	12	-	12	-
Total VEBA trust assets, at fair value	$ 254	$ 5	$ 12	$ -
Receivables and payables, net (b)	1			
401(h) account assets	123			
Total other postretirement benefit plan assets	$ 378			

(a) In accordance with accounting guidance certain investments that are measured at fair value using the net asset value per share (NAV), or its equivalent, practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in the table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the statement of financial position.
(b) Receivables and payables represent amounts for investments sold/purchased but not yet settled along with interest and dividends earned but not yet received.

Investments in money market funds represent investments in funds that invest primarily in a diversified portfolio of investment grade money market instruments, including, but not limited to, commercial paper, notes, repurchase agreements and other evidences of indebtedness with a maturity not exceeding 13 months from the

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date of purchase. The primary objective of the fund is a level of current income consistent with stability of principal and liquidity. Redemptions can be made daily on this fund.

Investments in large-cap equity securities represent investments in a passively managed equity index fund that invests in securities and a combination of other collective funds. Fair value measurements are not obtained from a quoted price in an active market but are based on firm quotes of net asset values per share as provided by the trustee of the fund. Redemptions can be made daily on this fund.

Investments in commingled debt securities represent investments in a fund that invests in a diversified portfolio of investment grade long-duration fixed income securities. Redemptions can be made daily on these funds.

Investments in corporate bonds represent investment in a diversified portfolio of investment grade long-duration fixed income securities. The fair value of debt securities are generally based on evaluations that reflect observable market information, such as actual trade information for identical securities or for similar securities, adjusted for observable differences.

Investments in municipalities represent investments in a diverse mix of tax-exempt municipal securities. The fair value measurements for these securities are based on recently executed transactions for identical securities or for similar securities.

Expected Cash Flows - Defined Benefit Plans

While LKE's defined benefit pension plans have the option to utilize available prior year credit balances to meet current and future contribution requirements, KU contributed $46 million to LKE’s pension plan on behalf of its employees in January 2018. No additional contributions are expected in 2018.

LKE is not required to make contributions to its other postretirement benefit plan but has historically funded this plan in amounts equal to the postretirement benefit costs recognized. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid by the LKE plan for KU retirees.

	Allocated from LKE Pension Plan	Other Postretirement Benefits
2018	$ 29	$ 5
2019	30	5
2020	30	5
2021	30	5
2022	31	6
2023 - 2027	150	28

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Savings Plans

Substantially all employees of KU are eligible to participate in deferred savings plans (401(k)s). Employer contributions to the plans were $4 million each in 2017 and 2016.

9. Jointly Owned Facilities

At December 31, 2017 and 2016, the Balance Sheets reflect the owned interests in the facilities listed below.

	Ownership Interest	Electric Plant	Accumulated Depreciation	Construction Work in Progress
2017				
Generating Plants				
E.W. Brown Units 6-7	62.00%	$ 66	$ 27	$ -
Paddy's Run Unit 13 & E.W. Brown Unit 5	47.00%	46	13	-
Trimble County Unit 2	60.75%	817	140	96
Trimble County Units 5-6	71.00%	76	20	-
Trimble County Units 7-10	63.00%	120	34	-
Cane Run Unit 7	78.00%	431	31	4
E.W. Brown Solar Unit	61.00%	16	1	-
2016				
Generating Plants				
E.W. Brown Units 6-7	62.00%	$ 65	$ 23	$ -
Paddy's Run Unit 13 & E.W. Brown Unit 5	47.00%	50	11	1
Trimble County Unit 2	60.75%	812	129	40
Trimble County Units 5-6	71.00%	74	19	-
Trimble County Units 7-10	63.00%	121	29	1
Cane Run Unit 7	78.00%	412	18	4
E.W. Brown Solar Unit	61.00%	15	-	-

KU provides its own funding for its share of each of the above facilities. KU 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.

10. Commitments and Contingencies

Energy Purchase Commitments

KU enters into purchase contracts to supply the coal and natural gas requirements for generation facilities. These contracts include the following commitments:

Contract Type	Maximum Maturity Date
Natural Gas Fuel	2019
Coal	2023
Coal Transportation and Fleeting Services	2024
Natural Gas Transportation	2026

KU has a power purchase agreement with OVEC expiring in June 2040. See "Guarantees and Other Assurances" below for information on the OVEC power purchase contract, including recent developments in credit or debt conditions relating to OVEC. Future obligations for power purchases from OVEC are unconditional demand payments, comprised of debt-service payments and contractually-required reimbursements of plant operating, maintenance and other expenses, and are projected as follows:

2018	$	9
2019		8
2020		8
2021		8
2022		8
Thereafter		141
	$	182

KU had total energy purchases under the OVEC power purchase agreement of $6 million and $7 million for the years ended December 31, 2017 and 2016.

Legal Matters

KU is involved in legal proceedings, claims and litigation in the ordinary course of business and cannot predict the outcome of such matters, or whether such matters may result in material liabilities, unless otherwise noted.

E.W. Brown Environmental Claims

On July 12, 2017, the Kentucky Waterways Alliance and the Sierra Club filed a citizen suit complaint against KU in the U.S. District Court for the Eastern District of Kentucky alleging discharges at the E.W. Brown plant in violation of the Clean Water Act and the plant's water discharge permit and alleging contamination that may present an imminent and substantial endangerment in violation of the RCRA. The plaintiffs' suit relates to prior notices of intent to file a citizen suit submitted in October and November 2015 and October 2016. These plaintiffs sought injunctive relief ordering KU to take all actions necessary to comply with the Clean Water Act and RCRA, including ceasing the discharges in question, abating effects associated with prior discharges and eliminating the alleged imminent and substantial endangerment. These plaintiffs also sought assessment of civil penalties and an award of litigation costs and attorney fees. On December 28, 2017 the U.S. District Court for the Eastern District of Kentucky issued an order dismissing the Clean Water Act and RCRA complaints against KU in their entirety. On January 26, 2018, the plaintiffs appealed the dismissal order to the U.S. Court of Appeals for the Sixth Circuit. KU is undertaking extensive remedial measures at the Brown plant including closure of the former ash pond, implementation of a groundwater remedial action plan, and performance of a corrective action plan including aquatic study of adjacent surface waters and risk assessment. KU cannot predict the outcome of these matters.

Trimble County Water Discharge Permit

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet (KEEC) 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 KEEC issued a final order upholding the permit, which was subsequently appealed by the environmental groups. In September 2013, the Franklin Circuit Court reversed the KEEC order and remanded the permit to the agency for further proceedings. LG&E and the KEEC appealed the order to the Kentucky Court of Appeals. In July 2015, the Court of Appeals upheld the lower court ruling. LG&E and the KEEC moved for discretionary review by the Kentucky Supreme Court. In February 2016, the Kentucky Supreme Court issued an order granting discretionary review and oral arguments were held in September 2016. On April 27, 2017, the Kentucky Supreme Court issued an order reversing the decision of the appellate court and upholding the permit issued to LG&E by the KEEC.

Trimble County Landfill

Various state and federal permits and regulatory approvals are required in order to construct a landfill at the Trimble County plant to be used for disposal of CCRs. In October 2016, the Kentucky Division of Water issued a water quality certification and in February 2017, the Kentucky Division of Waste Management issued a "special waste" landfill permit. In March 2017, the Sierra Club and a resident adjacent to the plant filed administrative challenges to the landfill permit which were subsequently dismissed by agreed order entered in August 2017. In June 2017, the U.S. Army Corps of Engineers issued a dredge and fill permit, the final approval required for construction of the landfill. KU believes that all permits and regulatory approvals issued for the project comply with applicable state and federal laws.

Regulatory Issues

See Note 4 for information on regulatory matters related to utility rate regulation.

Electricity - Reliability Standards

The NERC is responsible for establishing and enforcing mandatory reliability standards (Reliability Standards)

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regarding the bulk electric system in North America. 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 electric system, including electric utility companies, generators and marketers. Under the Federal Power Act, the FERC may assess civil penalties for certain violations.

KU monitors its compliance with the Reliability Standards and self-reports or self-logs potential violations of applicable reliability requirements whenever identified, and submits accompanying mitigation plans, as required. The resolution of a small number of potential violations is pending. Penalties incurred to date have not been significant. Any Regional Reliability Entity (including RFC or SERC) determination concerning the resolution of violations of the Reliability Standards remains subject to the approval of the NERC and the FERC.

In the course of implementing its programs to ensure compliance with the Reliability Standards, certain other instances of potential non-compliance may be identified from time to time. KU cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any.

Environmental Matters

Due to the environmental issues discussed below or other environmental matters, it may be necessary for KU to modify, curtail, replace or cease operation of certain facilities or performance of certain operations to comply with statutes, regulations and other requirements of regulatory bodies or courts. In addition, legal challenges to new environmental permits or rules add to the uncertainty of estimating the future cost of these permits and rules. Finally, the regulatory reviews specified in the President's March 2017 Executive Order (the March 2017 Executive Order) promoting energy independence and economic growth could result in future regulatory changes and additional uncertainty.

KU is entitled to recover, through the ECR mechanism, certain costs of complying with the Clean Air Act, as amended, and those federal, state or local environmental requirements applicable to coal combustion wastes and by-products from facilities that generate electricity from coal in accordance with approved compliance plans. Costs not covered by the ECR mechanism are subject to rate recovery before the KPSC, VSCC or the FERC, if applicable. KU can provide no assurances as to the ultimate outcome of future environmental or rate proceedings before regulatory authorities.

Air

NAAQS

The Clean Air Act, which regulates air pollutants from mobile and stationary sources in the United States, has a significant impact on the operation of fossil fuel generation plants. Among other things, the Clean Air Act requires the EPA periodically to review and establish concentration levels in the ambient air for six pollutants to protect public health and welfare. The six pollutants are carbon monoxide, lead, nitrogen dioxide, ozone (contributed to by nitrogen oxide emissions), particulate matter and sulfur dioxide. The established concentration levels for these six pollutants are known as NAAQS. Under the Clean Air Act, the EPA is

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required to reassess the NAAQS on a five-year schedule.

Federal environmental regulations of these six pollutants require states to adopt implementation plans, known as state implementation plans, which detail how the state will attain the standards that are mandated by the relevant law or regulation. Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (non-attainment areas), and must develop a state implementation plan both to bring non-attainment areas into compliance with the NAAQS and to maintain good air quality in attainment areas. In addition, for attainment of ozone and fine particulates standards, states in the eastern portion of the country, including Kentucky, are subject to a regional program developed by the EPA known as the Cross-State Air Pollution Rule. The NAAQS, future revisions to the NAAQS and state implementation plans, or future revisions to regional programs, may require installation of additional pollution controls, the costs of which KU believes are subject to cost recovery.

Although KU does not anticipate significant costs to comply with these programs, changes in market or operating conditions could result in different costs than anticipated.

Ozone

The EPA issued the current ozone standard in October 2015. The states and the EPA are required to determine (based on ambient air monitoring data) those areas that meet the standard and those that are in non-attainment. The EPA was scheduled to designate areas as being in attainment or nonattainment of the current ozone standard by no later than October 2017 which was to be followed by further regulatory proceedings identifying compliance measures and deadlines. However, the current implementation and compliance schedule is uncertain because the EPA failed to make nonattainment demonstrations by the applicable deadline. In addition, some industry groups have requested the EPA to defer implementation of the 2015 ozone standard, but the EPA has not yet acted on this request. While implementation of the 2015 ozone standard could potentially require the addition of SCRs at some generating units, KU is currently unable to determine what the compliance measures and deadlines may ultimately be with respect to the new standard.

States are also obligated to address interstate transport issues associated with ozone standards through the establishment of "good neighbor" state implementation plans for those states that are found to contribute significantly to another state's non-attainment. As a result of a partial consent decree addressing claims regarding federal implementation, the EPA and several states, including Kentucky, are evaluating the need for further nitrogen oxide reductions from fossil-fueled plants to address interstate impacts. While KU is unable to predict the outcome of ongoing and future evaluations by the EPA and the states, such evaluations could potentially result in requirements for nitrogen oxide reductions beyond those currently required under the Cross State Air Pollution Rule.

Sulfur Dioxide

In 2010, the EPA issued the current NAAQS for sulfur dioxide and required states to identify areas that meet those standards and areas that are in "non-attainment". In July 2013, the EPA finalized non-attainment designations for parts of the country, including part of Jefferson County in Kentucky. Attainment must be achieved by 2018. KU does not anticipate any further measures to achieve compliance with the new sulfur dioxide standards.

Climate Change

There is continuing world-wide attention focused on issues related to climate change. In June 2016, President Obama announced that the United States, Canada and Mexico established the North American Climate, Clean Energy, and Environment Partnership Plan, which specifies actions to promote clean energy, address climate change and protect the environment. The plan includes a goal to provide 50% of the energy used in North America from clean energy sources by 2025. The plan does not impose any nation-specific requirements.

In December 2015, 195 nations, including the U.S., signed the Paris Agreement on Climate, which establishes a comprehensive framework for the reduction of GHG emissions from both developed and developing nations. Although the agreement does not establish binding reduction requirements, it requires each nation to prepare, communicate, and maintain GHG reduction commitments. Reductions can be achieved in a variety of ways, including energy conservation, power plant efficiency improvements, reduced utilization of coal-fired generation or replacing coal-fired generation with natural gas or renewable generation. Based on the EPA's rules issued in 2015 imposing GHG emission standards for both new and existing power plants, the U.S. committed to an initial reduction target of 26% to 28% below 2005 levels by 2025. However, on June 1, 2017, President Trump announced a plan to withdraw from the Paris Agreement and undertake negotiations to reenter the current agreement or enter a new agreement on terms more favorable to the U.S. Under the terms of the Paris Agreement, any U.S. withdrawal would not be complete until November 2020.

Additionally, the March 2017 Executive Order directed the EPA to review its 2015 greenhouse gas rules for consistency with certain policy directives and suspend, revise, or rescind those rules as appropriate. The March 2017 Executive Order also directs rescission of specified guidance, directives, and prior Presidential actions regarding climate change. KU cannot predict the outcome of such regulatory actions or the impact, if any, on plant operations, rate treatment or future capital or operating needs.

The EPA's Rules under Section 111 of the Clean Air Act

There continues to be uncertainty around the EPA's regulation of existing coal-fired power plants. In 2015 the EPA had finalized rules imposing GHG emission standards for both new and existing power plants and had proposed a federal implementation plan that would apply to any states that failed to submit an acceptable state implementation plan to reduce GHG emissions on a state-by-state basis (the 2015 EPA Rules).

Following legal challenges to the 2015 EPA Rules, a stay of those rules by the U.S. Supreme Court, and the President's March 2017 Executive Order (requiring the EPA to review the 2015 EPA Rules), however, in October 2017, the EPA proposed to rescind the 2015 EPA Rules and in December 2017, released an advanced notice of proposed rulemaking for a replacement rule (Replacement Rules) which contemplates GHG reductions based on "inside the fence" measures implemented at individual plants. The contemplated approach in the Replacement Rules is a more limited approach than that taken in the 2015 EPA Rules which had included assumed increased levels of fuel switching and renewable energy in determining the level of emission reduction required by each state. At present, the 2015 EPA Rules remain stayed and the Replacement Rules have not yet been published.

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In April 2014, the Kentucky General Assembly passed legislation limiting the measures that the Kentucky Energy and Environment Cabinet may consider in setting performance standards to comply with the 2015 EPA Rules, if enacted. The legislation provides that such state GHG performance standards will be based on emission reductions, efficiency measures and other improvements available at each power plant, rather than renewable energy, end-use energy efficiency, fuel switching and re-dispatch. These statutory restrictions are consistent with the EPA's notice of proposed rulemaking on the Replacement Rules.

KU is monitoring developments at the state and federal level. Until there is more clarity about the potential requirements that may be imposed under the Replacement Rules and Kentucky's implementation plan, KU cannot predict the potential impact, if any, on plant operations, future capital or operating costs. KU believes that the costs, which could be significant, would be subject to rate recovery.

Water/Waste

CCRs

In April 2015, the EPA published its final rule regulating CCRs. CCRs include fly ash, bottom ash and sulfur dioxide scrubber wastes. The rule became effective in October 2015. It imposes extensive new requirements, including location restrictions, design and operating standards, groundwater monitoring and corrective action requirements, and closure and post-closure care requirements on CCR impoundments and landfills that are located on active power plants and not closed. Under the rule, CCRs are regulated as non-hazardous under Subtitle D of RCRA and beneficial use of CCRs is allowed, with some restrictions. The rule's requirements for covered CCR impoundments and landfills include implementation of groundwater monitoring and commencement or completion of closure activities generally between three and ten years from certain triggering events. The rule requires posting of compliance documentation on a publicly accessible website. Industry groups, environmental groups, individual companies and others have filed legal challenges to the final rule, which are pending before the D.C. Circuit Court of Appeals. The EPA has advised the court that it expects to reconsider certain aspects of the CCR Rule in the near future.

In January 2017, Kentucky issued a new state rule relating to CCR matters, effective May 2017, aimed at reflecting the requirements of the federal CCR Rule. In May 2017, a resident adjacent to KU’s and LG&E’s Trimble County plant filed a lawsuit in Franklin County, Kentucky Circuit Court against the Kentucky Energy and Environmental Cabinet and LG&E seeking to invalidate the new rule. On January 31, 2018, the state court issued an opinion invalidating certain elements of the new rule. KU cannot predict the ultimate outcome of the litigation. KU and LG&E presently operate their Trimble County facilities under continuing permits authorized via the former program and do not currently anticipate material impacts as a result of the challenge to the new rule. Separately, in December 2016, federal legislation was enacted that authorized the EPA to approve equally protective state programs that would operate in lieu of the CCR Rule. The Kentucky Energy and Environmental Cabinet indicated it may propose rules under such authority in the future.

KU received KPSC approval for a compliance plan providing for construction of additional landfill capacity at the E.W. Brown station, closure of impoundments at the Trimble County, E.W. Brown, and Ghent stations, and construction of process water management facilities at those plants. In addition to the foregoing measures required for compliance with federal CCR rule requirements, KU also received KPSC approval for its plans to

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close impoundments at the retired Green River, Pineville and Tyrone plants to comply with applicable state law requirements. See Note 4 for additional information.

In connection with the final CCR rule, KU recorded adjustments to existing AROs during 2016 and 2017. See Note 15 for additional information. Further changes to AROs, current capital plans or operating costs may be required as estimates are refined based on closure developments, groundwater monitoring results, and regulatory or legal proceedings. Costs relating to this rule are subject to rate recovery.

Clean Water Act

Regulations under the federal Clean Water Act dictate permitting and mitigation requirements for facilities and construction projects in the United States. Many of those requirements relate to power plant operations, including requirements related to the treatment of pollutants in effluents prior to discharge, the temperature of effluent discharges and the location, design and construction of cooling water intake structures at generating facilities, standards intended to protect aquatic organisms that become trapped at or pulled through cooling water intake structures at generating facilities. The requirements could impose significant costs for KU, which are subject to rate recovery.

ELGs

In September 2015, the EPA released its final ELGs for wastewater discharge permits for new and existing steam electric generating facilities. The rule provides strict technology-based discharge limitations for control of pollutants in scrubber wastewater, fly ash and bottom ash transport water, mercury control wastewater, gasification wastewater and combustion residual leachate. The new guidelines require deployment of additional control technologies providing physical, chemical and biological treatment of wastewaters. The guidelines also mandate operational changes including "no discharge" requirements for fly ash and bottom ash transport waters and mercury control wastewaters. The implementation date for individual generating stations will be determined by the states on a case-by-case basis according to criteria provided by the EPA. Industry groups, environmental groups, individual companies and others have filed legal challenges to the final rule, which have been consolidated before the U.S. Court of Appeals for the Fifth Circuit. In April 2017, the EPA announced that it would grant petitions for reconsideration of the rule. In September 2017, the EPA published in the Federal Register a proposed rule that would postpone the compliance date for requirements relating to bottom ash transport waters and scrubber wastewaters discharge limits. The EPA expects to complete its reconsideration of best available technology standards by the fall of 2020. Upon completion of the ongoing regulatory proceedings, the rule will be implemented by the states in the course of their normal permitting activities. KU is developing compliance strategies and schedules and is unable to predict the outcome of the EPA's pending reconsideration of the rule or fully estimate compliance costs or timing. Additionally, certain aspects of these compliance plans and estimates relate to developments in state water quality standards, which are separate from the ELG rule or its implementation. Costs to comply with ELGs or other discharge limits, which are expected to be significant, are subject to rate recovery.

Seepages and Groundwater Infiltration

Seepages or groundwater infiltration have been detected at active and retired wastewater basins and landfills at

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various KU plants. KU completed, or is completing, assessments of seepages or groundwater infiltration at various facilities and completed, or is working with agencies to implement, further testing, monitoring or abatement measures, where applicable. A range of reasonably possible costs cannot currently be estimated. Depending on the circumstances in each case, certain costs, which may be subject to rate recovery, could be significant.

Other Issues

In June 2016, the "Frank Lautenberg Chemical Safety Act" took effect as an amendment to the Toxic Substance Control Act (TSCA). The Act made no changes to the pre-existing TSCA rules as it pertains to polychlorinated biphenyls (PCB). The EPA continues to reassess its PCB regulations as part of the 2010 Advanced Notice of Proposed Rulemaking (ANPRM). The EPA's ANPRM rulemaking is to occur in two phases. Only the second part of the rule, currently scheduled for November 2017, is applicable to KU operations. This part of the rule relates to the use of PCBs in electrical equipment and natural gas pipelines, as well as continued use of PCB-contaminated porous surfaces. Although the first rulemaking will not directly affect KU’s operations, it may indicate certain approaches or principles to occur in the later rulemaking which may affect KU’s facilities, including phase-out of some or all equipment containing PCBs. Should such a phase-out be required, the costs, which are subject to rate recovery, could be significant.

Superfund and Other Remediation

KU is investigating, responding to agency inquiries, taking various measures, remediating, or have completed the remediation of, for several sites that were not addressed under a regulatory program such as Superfund, but for which it may be liable for remediation. These include a number of former coal gas manufacturing plants in Kentucky previously owned or operated or currently owned by predecessors or affiliates of KU. To date, the costs of these sites have not been significant.

There are additional sites, formerly owned or operated by KU predecessors or affiliates. KU lacks sufficient information on such additional sites and are therefore is unable to estimate any potential liability it may have or a range of reasonably possible losses, if any, related to these matters.

The EPA is evaluating the risks associated with polycyclic aromatic hydrocarbons and naphthalene, chemical by-products of coal gas manufacturing. As a result of the EPA's evaluation, individual states may establish stricter standards for water quality and soil cleanup. This could require KU to take more extensive assessment and remedial actions at former coal gas manufacturing plants. KU cannot estimate a range of reasonably possible losses, if any, related to these matters.

From time to time, KU undertakes testing, monitoring or remedial action in response to notices of violations, 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 its operations and undertakes similar actions necessary to resolve environmental matters that arise in the course of normal operations. Based on analyses to date, resolution of these environmental matters is not expected to have a significant adverse impact on operations.

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Future cleanup or remediation work at sites under review, or at sites not yet identified, may result in significant additional costs. Insurance policies maintained by KU may be applicable to certain of the costs or other obligations related to these matters but the amount of insurance coverage or reimbursement cannot be estimated or assured.

Other

Labor Union Agreements

In August 2017, KU and the United Steelworkers of America ratified a three-year labor agreement through August 2020. The agreement covers approximately 54 employees. The terms of the new labor agreement do not have a significant impact on KU’s financial results.

KU cannot predict the outcome of future union labor negotiations.

Guarantees and Other Assurances

In the normal course of business, KU enters into agreements that provide financial performance assurance to third parties. 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 creditworthiness or to facilitate commercial activities.

Pursuant to the OVEC power purchase contract, KU is obligated to pay for its share of OVEC's excess debt service, post-retirement and decommissioning costs, as well as any shortfall from amounts included within a demand charge designed and expected to cover these costs over the term of the contract. KU's proportionate share of OVEC's outstanding debt was $36 million at December 31, 2017. The maximum exposure and the expiration date of these potential obligations are not presently determinable. See "Energy Purchase Commitments" above for additional information on the OVEC power purchase contract. In connection with recent credit market related developments at OVEC or certain of its sponsors, such parties, including KU, have allowed implementation of a limited, partial OVEC reserve fund for debt costs and are analyzing certain potential additional credit support actions to preserve OVEC's access to credit markets or mitigate risks or adverse impacts relating thereto, including increased interest costs and accelerated maturities of OVEC's existing short and long-term debt. The ultimate outcome of these matters, including any potential impact on KU's obligations relating to OVEC debt under the power purchase contract cannot be predicted.

KU provides other miscellaneous guarantees through contracts entered into in the normal course of business. These guarantees are primarily in the form of indemnification or warranties related to services or equipment and vary in duration. The amounts of these guarantees often are not explicitly stated, and the overall maximum amount of the obligation under such guarantees cannot be reasonably estimated. Historically, no significant payments have been made with respect to these types of guarantees and the probability of payment/performance under these guarantees is remote.

PPL, on behalf of itself and certain of its subsidiaries, including KU, maintains insurance that covers liability assumed under contract for bodily injury and property damage. The coverage provides maximum aggregate coverage of $225 million. This insurance may be applicable to obligations under certain of these contractual arrangements.

11. Related Party Transactions

Wholesale Sales and Purchases

KU and LG&E jointly dispatch their generation units with the lowest cost generation used to serve their retail customers. When KU has excess generation capacity after serving its own retail customers and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU, and vice versa. 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 plus any split savings. Savings realized from such intercompany transactions are shared equally between both companies. The volume of energy each company has to sell to the other is dependent on its retail customers' needs and its available generation.

Support Costs

LKS provides KU with administrative, management and support services. The costs of these services are charged to KU as direct support costs. General costs that cannot be directly attributed to a specific LKE subsidiary are allocated and charged to KU and other subsidiaries as indirect support costs. LKS bases its indirect allocations on the subsidiaries' number of employees, total assets, revenues, number of customers and/or other statistical information.

LKS charged KU $190 million and $194 million for the years ended December 31, 2017 and 2016, including amounts applied to accounts that are further distributed between capital and expense on KU’s books, based on methods that are believed to be reasonable.

In addition to the charges for services noted above, LKS makes payments on behalf of KU for fuel purchases and other costs for products or services provided by third parties. KU and LG&E also provide services to each other and to LKS. Billings between KU and LG&E relate to labor and overhead costs associated with union and hourly employees performing work for the other company, charges related to jointly owned generating units and other miscellaneous charges. Tax settlements between LKE and KU are reimbursed through LKS.

Intercompany Borrowings

KU participates in an intercompany money pool agreement whereby LKE and/or LG&E make available to KU funds up to $500 million at an interest rate based on a market index of commercial paper issues. No balances were outstanding at December 31, 2017 and 2016. Interest income incurred on the money pool agreement with LG&E was not significant for 2017 and 2016.

Intercompany Derivatives

Periodically, KU enters into forward-starting interest rate swaps with PPL. These hedging instruments have terms identical to forward-starting swaps entered into by PPL with third parties.

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Other

See Note 1 for a discussion regarding the intercompany tax sharing agreement. See Note 8 for discussions regarding intercompany allocations associated with defined benefits.

12. Fair Value Measurements

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). 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) are used to measure the fair value of an asset or liability, as appropriate. 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. The fair value of a group of financial assets and liabilities is measured on a net basis. Transfers between levels are recognized at end-of-reporting-period values. During 2017 and 2016, there were no transfers between Level 1 and Level 2. See Note 1 for information on the levels in the fair value hierarchy.

Recurring Fair Value Measurements

The assets and liabilities measured at fair value were:

	December 31, 2017			
	Total	Level 1	Level 2	Level 3
Assets				
Cash and cash equivalents	$ 15	$ 15	$ -	$ -
Total assets	$ 15	$ 15	$ -	$ -

	December 31, 2016			
	Total	Level 1	Level 2	Level 3
Assets				
Cash and cash equivalents	$ 7	$ 7	$ -	$ -
Total assets	$ 7	$ 7	$ -	$ -

Price Risk Management Assets/Liabilities - Interest Rate Swaps

To manage interest rate risk, KU uses interest rate contracts such as forward-starting swaps. An income approach is used 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, market information cannot practicably be obtained to value credit risk and therefore internal models are relied upon. These models use projected probabilities of default and estimated recovery rates 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 amounts of long-term debt on the Balance Sheets and their estimated fair values are set forth below. The fair values were estimated using an income approach by discounting future cash flows at estimated current cost of funding rates, which incorporate KU's credit risk. Long-term debt is classified as Level 2. The effect of third-party credit enhancements is not included in the fair value measurement.

December 31, 2017		December 31, 2016	
Carrying Amount (a)	Fair Value	Carrying Amount (a)	Fair Value
$ 2,328	$ 2,605	$ 2,327	$ 2,514

(a) Amount is net of debt issuance costs.

The carrying amounts of other current financial instruments (except for long-term debt due within one year) approximate their fair values because of their short-term nature.

13. Derivative Instruments and Hedging Activities

Risk Management Objectives

PPL has a risk management policy approved by the Board of Directors to manage market risk associated with commodities and interest rates on debt issuances (including price, liquidity and volumetric risk), and credit risk (including non-performance risk and payment default risk). The Risk Management Committee, comprised of senior management and chaired by the Senior Director - Risk Management, 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, verification of risk and transaction limits and the coordination and reporting of the Enterprise Risk Management program.

Market Risk

Market risk includes the potential loss that may be incurred as a result of price changes associated with a particular financial or commodity instrument as well as market liquidity and volumetric risks. Forward contracts and swaps are utilized as part of risk management strategies to minimize unanticipated fluctuations in earnings caused by changes in commodity prices and interest rates. Many of these contracts meet the definition of a derivative. All derivatives are recognized on the Balance Sheets at their fair value, unless NPNS is elected.

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The following summarizes the market risks that affect KU.

Interest rate risk

- KU is exposed to interest rate risk associated with forecasted fixed-rate debt issuances. KU utilizes forward starting interest rate swaps to hedge changes in benchmark interest rates, when appropriate, in connection with future debt issuances.

- KU is exposed to interest rate risk associated with debt securities and derivatives held by defined benefit plans. This risk is significantly mitigated to the extent that the plans are sponsored on behalf of KU due to the recovery methods in place.

Commodity price risk

- KU's rates include certain mechanisms for fuel, fuel-related expenses and energy purchases. These mechanisms generally provide for timely recovery of market price fluctuations associated with these expenses.

Volumetric risk

- KU is exposed to volumetric risk on retail sales, mainly due to weather and other economic conditions for which there is limited mitigation between rate cases.

Equity securities price risk

- KU is exposed to equity securities price risk associated with the fair value of the defined benefit plans' assets. This risk is significantly mitigated due to the recovery methods in place.

Credit Risk

Credit risk is the potential loss that may be incurred due to a counterparty's non-performance.

In the event a supplier of KU defaults on its obligation, KU would be required to seek replacement power or replacement fuel in the market. In general, subject to regulatory review or other processes, appropriate incremental costs incurred by KU would be recoverable from customers through applicable rate mechanisms, thereby mitigating its financial risk.

KU has credit policies in place to manage credit risk, including the use of an established credit approval process, daily monitoring of counterparty positions and the use of master netting agreements or provisions. These agreements generally include credit mitigation provisions, such as margin, prepayment or collateral requirements. KU may request additional credit assurance, in certain circumstances, in the event that the counterparties' credit ratings fall below investment grade, their tangible net worth falls below specified percentages or their exposures exceed an established credit limit.

Interest Rate Risk

KU issues debt to finance its operations, which exposes it to interest rate risk. A variety of financial derivative instruments are utilized to adjust the mix of fixed and floating interest rates in its debt portfolios, adjust the duration of the debt portfolios and lock in benchmark interest rates in anticipation of future financing, when appropriate. Risk limits under KU's risk management program are designed to balance risk exposure to volatility in interest expense and changes in the fair value of the debt portfolio due to changes in benchmark interest rates. In addition, KU's interest rate risk is potentially mitigated as a result of the existing regulatory framework or the timing of rate cases.

Accounting and Reporting

All derivative instruments are recorded at fair value on the Balance Sheets as an asset or liability unless NPNS is elected. NPNS contracts include physical purchase contracts. Changes in the fair value of derivatives not designated as NPNS are recognized in earnings unless specific hedge accounting criteria are met and designated as such. See Note 4 for amounts recorded in regulatory assets and regulatory liabilities at December 31, 2017 and 2016.

See Note 1 for additional information on accounting policies related to derivative instruments.

Offsetting Derivative Instruments

KU has master netting arrangements in place and also enters into agreements pursuant to which it purchases or sells certain energy and other products. Under the agreements, upon termination of the agreement as a result of a default or other termination event, the non-defaulting party typically would have a right to set off amounts owed under the agreement against any other obligations arising between the two parties (whether under the agreement or not), whether matured or contingent and irrespective of the currency, place of payment or place of booking of the obligation.

KU has elected not to offset derivative assets and liabilities and not to offset net derivative positions against the right to reclaim cash collateral pledged (an asset) or the obligation to return cash collateral received (a liability) under derivatives agreements.

Credit Risk-Related Contingent Features

Certain derivative contracts contain credit risk-related contingent features which, when in a net liability position, would permit the counterparties to require the transfer of additional collateral upon a decrease in KU's credit ratings. Most of these features would require the transfer of additional collateral or permit the counterparty to terminate the contract if the applicable credit rating were to fall below investment grade. Some of these features also would allow the counterparty to require additional collateral upon each downgrade in credit rating at levels that remain above investment grade. In either case, if the applicable credit rating were to fall below investment grade, most of these credit contingent features require either immediate payment of the net liability as a termination payment or immediate and ongoing full collateralization on derivative instruments in net liability positions.

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Additionally, certain derivative contracts contain credit risk-related contingent features that require adequate assurance of performance be provided if the other party has reasonable concerns regarding KU's performance obligations under the contracts. 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.

At December 31, 2017, KU had no derivative contracts in a net liability position that contain credit risk-related contingent features.

14. Other Intangible Assets

The gross carrying amount and the accumulated amortization of other intangible assets as of December 31 were:

	2017		2016	
	Gross Carrying Amount	**Accumulated Amortization**	**Gross Carrying Amount**	**Accumulated Amortization**
Subject to amortization:				
Coal contracts (a)	$ -	$ -	$ 145	$ 145
Land and transmission rights	14	2	14	2
OVEC power purchase agreement (b)	39	18	39	15
Total subject to amortization	$ 53	$ 20	$ 198	$ 162

(a) Gross carrying amount represents the fair value at the acquisition date of coal 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 was amortized over the same period as the intangible asset, eliminating any income statement impact.
(b) Gross carrying amount represents the fair value at the acquisition date of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to this contract, which is being amortized over the same period as the intangible asset, eliminating any income statement impact. See Note 4 for additional information.

Long-term intangible assets are presented as "Other intangibles" on the Balance Sheets.

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Amortization expense was as follows:

	2017	2016
Intangible assets with no regulatory offset	$ -	$ 1
Intangible assets with regulatory offset	3	11
Total	$ 3	$ 12

Amortization expense for each of the next five years is estimated to be:

	Intangible assets with regulatory offset
2018	$ 3
2019	3
2020	2
2021	2
2022	2

15. Asset Retirement Obligations

KU's AROs are primarily related to the final retirement of assets associated with generating units. KU's transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, no material AROs are recorded for transmission and distribution assets. As described in Notes 1 and 4, KU's ARO accretion and depreciation expenses are reclassified as a regulatory asset. ARO regulatory assets associated with certain CCR projects are amortized to expense in accordance with regulatory approvals. For other AROs, at the time of retirement, the related ARO regulatory asset is offset against the associated cost of removal regulatory liability, PP&E and ARO liability.

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The changes in the carrying amounts of AROs were as follows.

	2017	2016
ARO at beginning of period	$ 288	$ 360
Accretion	13	15
Changes in estimated timing or cost (a)	(46)	(76)
Obligations settled	(20)	(11)
ARO at end of period	$ 235	$ 288

(a) KU recorded decreases of $52 million and $90 million to the existing AROs during 2017 and 2016 related to the closure of CCR impoundments. These revisions are the result of changes in closure plans related to expected costs and timing of closures. Further changes to AROs, capital plans or operating costs may be required as estimates of future cash flows are refined based on closure developments and regulatory or legal proceedings.

See Note 10 for information on the final CCR rule and Note 4 for information on the rate recovery applications.

16. New Accounting Guidance Pending Adoption

Accounting for Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued accounting guidance that establishes a comprehensive new model for the recognition of revenue from contracts with customers. This model is based on the core principle that revenue should be recognized to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.

KU has completed an assessment of its revenue under this new guidance and has determined it will not have a material impact on current revenue recognition policies. KU’s operating revenues are derived primarily from tariff-based sales that result from providing electricity and natural gas to customers with no defined contractual term. Tariff-based sales are within the scope of the new guidance, and operating revenues under the new guidance will be equivalent to the electricity and natural gas delivered and billed in that period (including estimated billings), which is consistent with current practice.

The disclosure requirements included in the standard will result in increased information being provided to enable the users of the financial statements to understand the nature, amount, timing and uncertainty of revenue arising from contracts with customers. These disclosures will include disaggregation of revenues by geographic location, customer class or type of service. Some revenue arrangements, including alternative revenue programs and lease income, are excluded from the scope of the new guidance and will be accounted for and disclosed separately from revenues from contracts with customers. KU will also disclose the opening and closing balances of accounts receivable and any contract assets or contract liabilities resulting from contracts with customers.

KU adopted this guidance effective January 1, 2018 using the modified retrospective transition method.

Accounting for Leases

In February 2016, the FASB issued accounting guidance for leases. This new guidance requires lessees to recognize a right-of-use asset and a lease liability for virtually all of their leases (other than leases that meet the definition of a short-term lease). For income statement purposes, the FASB retained a dual model for lessees, requiring leases to be classified as either operating or finance. Operating leases will result in straight-line expense (similar to current operating leases) while finance leases will result in a front-loaded expense pattern (similar to current capital leases). Classification will be based on criteria that are largely similar to those applied in current lease accounting, but without explicit bright line tests.

Lessor accounting under the new guidance is similar to the current model, but updated to align with certain changes to the lessee model and the new revenue recognition standard. Similar to current practice, lessors will classify leases as operating, direct financing, or sales-type.

The standard is effective for public business entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018. Early adoption is permitted. The new standard must be adopted using a modified retrospective transition, and provides for certain practical expedients. One of these practical expedients allows entities to elect to not evaluate land easements as leases that exist or expired before the adoption date and were not previously accounted for as leases under current lease guidance. Transition will require application of the new guidance at the beginning of the earliest comparative period presented.

KU is currently assessing the impact of adopting this guidance and will adopt this guidance effective January 1, 2019.

Accounting for Financial Instrument Credit Losses

In June 2016, the FASB issued accounting guidance that requires the use of a current expected credit loss (CECL) model for the measurement of credit losses on financial instruments within the scope of this guidance, which includes accounts receivable. The CECL model requires an entity to measure credit losses using historical information, current information and reasonable and supportable forecasts of future events, rather than the incurred loss impairment model required under current GAAP.

For public business entities, this guidance will be applied using a modified retrospective approach and is effective for fiscal years beginning after December 15, 2019, and interim periods within those years. All entities may early adopt this guidance beginning after December 15, 2018, including interim periods within those years.

KU is currently assessing the impact of adopting this guidance and the period it will be adopted.

Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued accounting guidance that changes the GAAP income statement presentation of net periodic benefit cost. This new guidance requires the service cost component to be disaggregated from other

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components of net benefit cost and presented in the same income statement line items as other employee compensation costs arising from services rendered during the period. The other components of net periodic benefits will be presented separately from the line items that include the service cost and outside of any subtotal of operating income. Only the service cost component is eligible for capitalization.

For public business entities, the guidance on the presentation of the components of net periodic benefit costs will be applied retrospectively. The guidance that limits the capitalization to the service cost component of net periodic benefit costs will be applied prospectively. This guidance is effective for fiscal years beginning after December 15, 2017 and interim periods within those years. KU will adopt this guidance effective January 1, 2018.

For LKE’s U.S. defined benefit pension and LKE's other postretirement benefit plan allocated to KU, the adoption of this new guidance is not expected to have a material impact on either the presentation on the GAAP income statements or the amounts capitalized and related impact to expense, as the difference between the service cost and the non-service cost components of net periodic benefit costs has not historically been and is not expected to be material in 2018.

KU is finalizing the expected 2018 impacts of adopting the guidance as the amounts are affected by market conditions and assumptions selected at December 31, 2017.

The adoption of this guidance will have no impact on the FERC income statements and balance sheets and represent a FERC to GAAP reporting difference.

Improvements to Accounting for Hedging Activities

In August 2017, the FASB issued accounting guidance that reduces complexity when applying hedge accounting as well as improves transparency about an entity's risk management activities. This guidance eliminates recognizing hedge ineffectiveness for cash flow and net investment hedges and provides for the ability to perform subsequent effectiveness assessments qualitatively. The guidance also makes certain changes to allowable methodologies such as allowing entities to apply the short-cut method to partial-term fair value hedges of interest rate risk as well as expands the ability to apply the critical terms match method to cash flow hedges of groups of forecasted transactions. The guidance also updates certain recognition and presentation requirements as well as disclosure requirements.

For public business entities, this guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018. Early adoption is permitted. This standard must be adopted using a modified retrospective approach and provides for certain transition elections that must be made prior to the first effectiveness testing date after adoption.

KU is currently assessing the impact of adopting this guidance and the period it will be adopted.

Simplifying the Test for Goodwill Impairment

In January 2017, the FASB issued accounting guidance that simplifies the test for goodwill impairment by eliminating the second step of the quantitative test. The second step of the quantitative test requires a calculation of the implied fair value of goodwill, which is determined in the same manner as the amount of goodwill in a business combination. Under this new guidance, an entity will now compare the estimated fair value of a reporting unit with its carrying value and recognize an impairment charge for the amount the carrying amount exceeds the fair value of the reporting unit.

For public business entities, this guidance will be applied prospectively and is effective for annual or any interim goodwill impairment tests for fiscal years beginning after December 15, 2019. All entities may early adopt this guidance for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017.

KU is currently assessing the impact of adopting this guidance and the period it will be adopted.

17. Notes to Statement of Cash Flows

	December 31, 2017	December 31, 2016
Cash paid (received) during the period for:		
Income taxes	$ 34	$ 13
Interest	92	89
Significant noncash transactions:		
Accrued expenditures for property, plant and equipment	82	47

18. Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2017 up to February 22, 2018, the date that KU's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through March 21, 2018. These updates are included below.

TCJA Impact on Rates

On March 20, 2018, the KPSC issued an order in the regulatory proceedings related to the TCJA approving the parties' prior settlement agreement with certain modifications. The KPSC has estimated the impact of additional modifications to reduce KU's electricity revenues by an additional $17 million from the initial settlement amounts for the period January 2018 through April 2019. On March 26, 2018, KU filed a petition for reconsideration and request for hearing with the KPSC, taking exception with the KPSC's modifications and the process, and also requested certain relief from implementing the amounts represented by the additional reductions until the matter is fully resolved.

On March 22, 2018, KU reached a settlement regarding its ongoing rate case in Virginia. New rates, inclusive of TCJA impacts, will be effective June 1, 2018 and do not have a significant impact on KU. The settlement agreement is subject to review and approval by the VSCC.

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KU cannot predict the outcome of these proceedings.

See Note 4 for more information on the TCJA and associated regulatory proceedings.

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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				(1,627,215)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(185,989)
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				(185,989)
5	Balance of Account 219 at End of Preceding Quarter/Year				(1,813,204)
6	Balance of Account 219 at Beginning of Current Year				(1,813,204)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,813,204
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				1,813,204
10	Balance of Account 219 at End of Current Quarter/Year				

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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			(1,627,215)	[redacted]	[redacted]
2			(185,989)	[redacted]	[redacted]
3				[redacted]	[redacted]
4			(185,989)	265,627,602	265,441,613
5			(1,813,204)	[redacted]	[redacted]
6			(1,813,204)	[redacted]	[redacted]
7			1,813,204	[redacted]	[redacted]
8				[redacted]	[redacted]
9			1,813,204	257,108,756	258,921,960
10				[redacted]	[redacted]

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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)	8,340,664,002	8,340,664,002
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	934,606,971	934,606,971
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	9,275,270,973	9,275,270,973
9	Leased to Others		
10	Held for Future Use	1,912,920	1,912,920
11	Construction Work in Progress	321,167,940	321,167,940
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	9,598,351,833	9,598,351,833
14	Accum Prov for Depr, Amort, & Depl	3,238,141,782	3,238,141,782
15	Net Utility Plant (13 less 14)	6,360,210,051	6,360,210,051
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,179,437,123	3,179,437,123
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	58,704,659	58,704,659
22	Total In Service (18 thru 21)	3,238,141,782	3,238,141,782
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)	3,238,141,782	3,238,141,782

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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
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					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year: Amortization (d)	Changes during Year: Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)	Line No.
			1
			2
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			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	44,456	
3	(302) Franchises and Consents	55,919	
4	(303) Miscellaneous Intangible Plant	98,166,050	27,886,887
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	98,266,425	27,886,887
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	22,966,606	1,204,780
9	(311) Structures and Improvements	335,428,186	17,135,378
10	(312) Boiler Plant Equipment	3,941,701,027	36,015,475
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	335,905,667	5,819,635
13	(315) Accessory Electric Equipment	221,897,337	30,085,567
14	(316) Misc. Power Plant Equipment	36,915,885	79,918
15	(317) Asset Retirement Costs for Steam Production	248,144,715	15,089,823
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	5,142,959,423	105,430,576
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	879,312	
28	(331) Structures and Improvements	2,999,390	
29	(332) Reservoirs, Dams, and Waterways	21,885,646	
30	(333) Water Wheels, Turbines, and Generators	14,046,742	
31	(334) Accessory Electric Equipment	1,362,584	19,287
32	(335) Misc. Power PLant Equipment	316,948	12,426
33	(336) Roads, Railroads, and Bridges	234,509	
34	(337) Asset Retirement Costs for Hydraulic Production	645,788	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	42,370,919	31,713
36	D. Other Production Plant		
37	(340) Land and Land Rights	473,578	
38	(341) Structures and Improvements	85,079,275	628,135
39	(342) Fuel Holders, Products, and Accessories	61,764,003	841,768
40	(343) Prime Movers	642,925,882	17,619,755
41	(344) Generators	131,097,892	949,313
42	(345) Accessory Electric Equipment	66,335,266	12,270,404
43	(346) Misc. Power Plant Equipment	8,995,447	109,322
44	(347) Asset Retirement Costs for Other Production	403,344	34,623
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	997,074,687	32,453,320
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	6,182,405,029	137,915,609

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	31,890,109	
49	(352) Structures and Improvements	29,038,854	543,392
50	(353) Station Equipment	284,703,271	8,793,545
51	(354) Towers and Fixtures	76,458,681	1,593,370
52	(355) Poles and Fixtures	266,283,198	44,909,565
53	(356) Overhead Conductors and Devices	184,408,083	5,721,129
54	(357) Underground Conduit	448,760	
55	(358) Underground Conductors and Devices	1,118,444	181,217
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	568,682	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	874,918,082	61,742,218
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	7,728,975	9,400
61	(361) Structures and Improvements	12,752,991	1,807,106
62	(362) Station Equipment	187,778,407	12,834,658
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	376,412,777	14,537,061
65	(365) Overhead Conductors and Devices	355,489,781	22,237,748
66	(366) Underground Conduit	2,390,171	
67	(367) Underground Conductors and Devices	189,460,534	5,671,600
68	(368) Line Transformers	314,659,522	8,580,215
69	(369) Services	103,477,575	10,971,658
70	(370) Meters	79,256,935	1,620,861
71	(371) Installations on Customer Premises		6,164
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	116,439,694	5,239,367
74	(374) Asset Retirement Costs for Distribution Plant	693,404	33,437
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,746,540,766	83,549,275
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	3,430,117	99,551
87	(390) Structures and Improvements	59,203,904	3,959,517
88	(391) Office Furniture and Equipment	41,448,784	2,055,646
89	(392) Transportation Equipment	7,164,095	149,527
90	(393) Stores Equipment	910,971	
91	(394) Tools, Shop and Garage Equipment	12,666,874	910,806
92	(395) Laboratory Equipment		
93	(396) Power Operated Equipment	2,418,392	1,039,624
94	(397) Communication Equipment	55,633,856	1,222,225
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	182,876,993	9,436,896
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)	182,876,993	9,436,896
100	TOTAL (Accounts 101 and 106)	9,085,007,295	320,530,885
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)	9,085,007,295	320,530,885

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			44,456		2
			55,919		3
7,464,577			118,588,360		4
7,464,577			118,688,735		5
					6
					7
			24,171,386		8
562,235		-244,219	351,757,110		9
8,820,017			3,968,896,485		10
					11
4,439,606		221,969	337,507,665		12
115,476			251,867,428		13
416,467		22,250	36,601,586		14
203,134	-61,029,840		202,001,564		15
14,556,935	-61,029,840		5,172,803,224		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
23,675			855,637		27
			2,999,390		28
			21,885,646		29
			14,046,742		30
			1,381,871		31
			329,374		32
			234,509		33
			645,788		34
23,675			42,378,957		35
					36
			473,578		37
			85,707,410		38
19,123			62,586,648		39
2,558,080			657,987,557		40
475,999			131,571,206		41
			78,605,670		42
27,593			9,077,176		43
	-30,976		406,991		44
3,080,795	-30,976		1,026,416,236		45
17,661,405	-61,060,816		6,241,598,417		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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
			31,890,109		48
145,225		69,771	29,506,792		49
6,330,107		673,163	287,839,872		50
18,957			78,033,094		51
4,186,406			307,006,357		52
2,018,495			188,110,717		53
			448,760		54
567			1,299,094		55
					56
	-11,824		556,858		57
12,699,757	-11,824	742,934	924,691,653		58
					59
14,379			7,723,996		60
74,539		-73,625	14,411,933		61
1,908,264		-669,309	198,035,492		62
					63
1,857,901			389,091,937		64
8,166,162			369,561,367		65
			2,390,171		66
879,783			194,252,351		67
9,593,062			313,646,675		68
80,977			114,368,256		69
2,050,027			78,827,769		70
			6,164		71
					72
816,113			120,862,948		73
1,701	-54,949		670,191		74
25,442,908	-54,949	-742,934	1,803,849,250		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		-131,956	3,397,712		86
154,093			63,009,328		87
5,242,292			38,262,138		88
66,599			7,247,023		89
			910,971		90
274,114			13,303,566		91
					92
			3,458,016		93
1,917			56,854,164		94
					95
5,739,015		-131,956	186,442,918		96
					97
					98
5,739,015		-131,956	186,442,918		99
69,007,662	-61,127,589	-131,956	9,275,270,973		100
					101
					102
					103
69,007,662	-61,127,589	-131,956	9,275,270,973		104

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 204 Line No.: 15 Column: e
Adjustment due to changes in asset retirement cost estimates.

Schedule Page: 204 Line No.: 44 Column: e
Adjustment due to changes in asset retirement cost estimates.

Schedule Page: 204 Line No.: 57 Column: e
Adjustment due to changes in asset retirement cost estimates.

Schedule Page: 204 Line No.: 74 Column: e
Adjustment due to changes in asset retirement cost estimates.

Schedule Page: 204 Line No.: 86 Column: f
Transfer of land from Utility Plant (101) to Future Use (105).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
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46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Pennington Gap Substation #2	8/1/2013	2019-2020	324,088
3	Land at Green River Facility	11/1/2014	2029	309,541
4	London Substation	5/1/2016	2022	113,882
5	Kevil Service Center	3/1/2017	2019-2020	131,956
6	Polo Club Substation	4/1/2017	2025	792,599
7	Lonesome Pine Substation	7/1/2017	2019-2020	240,854
8				
9				
10				
11				
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14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
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36				
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44				
45				
46				
47	Total			1,912,920

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 214 Line No.: 5 Column: d

Transfer Land From Utility Plant (101) to Future Use (105).

Schedule Page: 214 Line No.: 6 Column: d

Transfer Land From Nonutility Property (121) to Future Use (105).

Schedule Page: 214 Line No.: 7 Column: d

Land Purchased for future substation site.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	STEAM PRODUCTION MAJOR	
2	GHENT PROCESS WATER SYSTEM	40,825,300
3	TRIMBLE COUNTY COAL COMBUSTION RESIDUALS TREATMENT - GYPSUM	27,862,080
4	TRIMBLE COUNTY COAL COMBUSTION RESIDUALS TREATMENT - LANDFILL	22,640,911
5	TRIMBLE COUNTY COAL COMBUSTION RESIDUALS TREATMENT - FLY ASH	22,387,341
6	TRIMBLE COUNTY PROCESS WATER SYSTEM	13,407,796
7	TRIMBLE COUNTY COAL COMBUSTION RESIDUALS TREATMENT - TRANSPORT	5,379,939
8	GHENT 1 FABRIC FILTER	4,151,144
9	GHENT 3 BOILER BURNER REPLACEMENT	3,964,486
10	GHENT BARGE UNLOADER RECERTIFICATION	2,415,105
11	GHENT CCR RULE NEW CONSTRUCTION	2,295,221
12	GHENT 2 4KV SWITCHGEAR	1,523,919
13	TRIMBLE COUNTY EFFLUENT WATER STUDY	1,327,544
14	GHENT 3 PARTIAL VERTICAL REHEATER REPLACEMENT	1,199,389
15	BROWN PROCESS WATER SYSTEM	1,164,579
16	GHENT 1 SCR CATALYST L3 NEW	1,082,386
17	GHENT 1 HG CONTROL INJECTION	1,066,864
18	GHENT 3 COOLING TOWER COMPLETE REBUILD	1,015,209
19	STEAM PRODUCTION MINOR	20,202,959
20		
21	HYDRAULIC POWER MAJOR	
22	HYDRAULIC POWER MINOR	1,066,655
23		
24	OTHER PRODUCTION MAJOR	
25	CANE RUN 7 NGCC SPARE PARTS INVENTORY	3,951,269
26	BROWN COMBUSTION TURBINE #11 INSPECTION & PARTS RECONDITION	2,483,291
27	OTHER PRODUCTION MINOR	1,093,078
28		
29	TRANSMISSION MAJOR	
30	PRIORITY REPLACEMENT TRANSMISSION LINES	11,748,267
31	POLE REPLACEMENTS ROSINE - LEITCHFIELD	4,345,266
32	GHENT 345KV SUBSTATION CONTROL HOUSE	3,565,634
33	POLE REPLACEMENTS PITTSBURG - LANCASTER	2,965,139
34	REMOTE TERMINAL UNIT REPLACEMENTS	2,767,237
35	GREEN RIVER 69KV CONTROL HOUSE REPLACEMENT	2,256,832
36	GHENT REDESIGN 138 KV - PROTECTION AND CONTROLS	1,918,608
37	POLE REPLACEMENTS LAKE REBA 162 - DELVINTA	1,917,160
38	BROWN NORTH SUBSTATION CIP SECURITY UPGRADES	1,870,686
39	GHENT REDESIGN 138 KV SUB	1,812,278
40	POLE REPLACEMENTS BROWN - FAWKES 138KV	1,643,295
41	TEP - HARDIN COUNTY TRANSFORMER ADDITION	1,577,691
42	RSC - HARDIN COUNTY PHYSICAL SECURITY UPGRADE	1,465,046
43	TOTAL	321,167,940

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	POLE REPLACEMENTS CARROLLTON - EAST FRANKFORT	1,464,128
2	SPARE 150 MVA TRANSFORMER - PINEVILLE	1,202,098
3	SPARE 138/69 185MVA TRANSFORMER	1,121,648
4	MT VERNON SUBSTATION ENHANCEMENTS	1,084,000
5	FAWKES FIREWALL/CAP BANK	1,034,888
6	REL - FMC 604 BREAKER ADDITION	1,024,287
7	POLE REPLACEMENTS KENTON - CARNTOWN	1,019,929
8	TRANSMISSION MINOR	28,736,204
9		
10	DISTRIBUTION MAJOR	
11	WEST HICKMAN SUBSTATION EXPANSION	3,850,139
12	VILEY ROAD SUBSTATION TRANSFORMER 2	3,047,680
13	KU PORTABLE TRANSFORMER	2,221,716
14	STONEWALL DISTRIBUTION SUBSTATION IMPROVEMENTS	2,033,860
15	RICHMOND NORTH SUBSTATION PROJECT	2,007,067
16	HUME ROAD SUBSTATION SYSTEM ENHANCEMENTS	1,995,876
17	LEXINGTON POLE INSPECTION	1,673,377
18	DISTRIBUTION CONTROL CENTER ENHANCEMENTS	1,037,509
19	DISTRIBUTION MINOR	20,937,927
20		
21	GENERAL MAJOR	
22	SOUTHEAST ALTERNATE TRANSPORT BUILDOUT	2,942,702
23	AUTOMATED METER MANAGEMENT SYSTEM	2,755,502
24	IT DISTRIBUTION AUTOMATION	1,417,160
25	GENERAL MINOR	16,161,664
26		
27	RESEARCH, DEVELOPMENT, AND DEMONSTRATING MINOR	38,975
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	321,167,940

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	3,000,600,788	3,000,600,788		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	238,531,335	238,531,335		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	395,549	395,549		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	1,283,097	1,283,097		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	240,209,981	240,209,981		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	61,338,250	61,338,250		
13	Cost of Removal	22,467,311	22,467,311		
14	Salvage (Credit)	675,638	675,638		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	83,129,923	83,129,923		
16	Other Debit or Cr. Items (Describe, details in footnote):	21,961,112	21,961,112		
17					
18	Book Cost or Asset Retirement Costs Retired	-204,835	-204,835		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,179,437,123	3,179,437,123		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,775,587,962	1,775,587,962		
21	Nuclear Production				
22	Hydraulic Production-Conventional	13,085,750	13,085,750		
23	Hydraulic Production-Pumped Storage				
24	Other Production	316,526,251	316,526,251		
25	Transmission	337,138,286	337,138,286		
26	Distribution	670,817,409	670,817,409		
27	Regional Transmission and Market Operation				
28	General	66,281,465	66,281,465		
29	TOTAL (Enter Total of lines 20 thru 28)	3,179,437,123	3,179,437,123		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 219 Line No.: 16 Column: c

Accrual for Depreciation on Asset Retirement Costs - (Other Regulatory Assets FERC 182.3)	$	20,891,683
Customer Payments Related to Construction Projects		1,069,429
	$	21,961,112

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	OVEC (2.50%)			
2	Common Stock, $100 par value, 2,500 shares			
3	250 shares	11/15/52		25,000
4	250 shares	01/14/53		25,000
5	250 shares	03/04/53		25,000
6	250 shares	04/15/53		25,000
7	250 shares	05/20/53		25,000
8	250 shares	06/22/53		25,000
9	500 shares	07/15/53		50,000
10	500 shares	07/31/53		50,000
11				
12	EEI (20%)			
13	Common Stock, $100 par value, 12,400 shares			
14	3,500 shares	03/06/51		
15	2,700 shares	08/03/53		
16	6,200 shares	12/30/58		
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	250,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
				1
				2
		25,000		3
		25,000		4
		25,000		5
		25,000		6
		25,000		7
		25,000		8
		50,000		9
		50,000		10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
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				38
				39
				40
				41
		250,000		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	98,479,707	62,248,036	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)	31,331,555	32,194,495	Electric
8	Transmission Plant (Estimated)	6,723,584	8,487,550	Electric
9	Distribution Plant (Estimated)	6,886,595	8,605,176	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	44,941,734	49,287,221	
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)	10,876,430	11,598,193	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	154,297,871	123,133,450	

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Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 227 Line No.: 16 Column: c

Balance at Beginning of Year	$	10,876,430
Total Debits		5,425,460
Total Credits		(4,703,697)
Balance at End of Year	$	11,598,193

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year	428,540.00	135,180	95,867.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	4,687.00			
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	20,104.00	3,942		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	413,123.00	131,238	95,867.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	1,106.50		1,106.50	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	1,106.50			
40	Balance-End of Year			1,106.50	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	1,106.50	70		
45	Gains		70		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2019 No. (f)	2019 Amt. (g)	2020 No. (h)	2020 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
77,535.00		77,535.00		2,015,910.00		2,695,387.00	135,180	1
								2
								3
				77,535.00		82,222.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						20,104.00	3,942	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
77,535.00		77,535.00		2,093,445.00		2,757,505.00	131,238	29
								30
								31
								32
								33
								34
								35
1,106.50		1,106.50		54,218.50		58,644.50		36
				2,213.00		2,213.00		37
								38
				1,106.50		2,213.00		39
1,106.50		1,106.50		55,325.00		58,644.50		40
								41
								42
								43
				1,106.50	16	2,213.00	86	44
					16		86	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year	28,531.00		17,515.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,005.00			
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	13,816.00			
19	Other:				
20	Charges to Account 549	242.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	15,478.00		17,515.00	
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				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2019		2020		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						46,046.00		1
								2
								3
						1,005.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						13,816.00		18
								19
						242.00		20
								21
								22
								23
								24
								25
								26
								27
								28
						32,993.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)]	Total Amount of Charges	Costs Recognised During Year	WRITTEN OFF DURING YEAR		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Feasability Studies				
3	Richmond North	587	561.6	587	561.6
4	Viley Road	302	561.6	302	561.6
5	Paynes Mill Road	226	561.6	226	561.6
6	System Impact Studies				
7	Richmond North			726	561.6
8	Corbin US Steel			363	561.6
9	Viley Road	147	561.6	147	561.6
10	Paris #4	147	561.6	147	561.6
11	Paynes Mill Road	226	561.6	226	561.6
12	Hume Road	226	561.6	226	561.6
13	Paris #4	76	561.6	76	561.6
14	Mount Vernon South	227	561.6	227	561.6
15	Lexington Stonewall	151	561.6	151	561.6
16	Shelbybville East	151	561.6	151	561.6
17	Lebanon East	151	561.6	151	561.6
18	200MW Bluegrass	975	561.6	975	561.6
19	Barton Sub	179	561.6	179	561.6
20	Gallatin/Lock 7	281	561.6	281	561.6
21	**Generation Studies**				
22	Feasability Studies				
23	35MW Solar	1,251	561.6	1,251	561.6
24	Facility Study				
25	35MW Solar	579	561.6		
26	System Impact Studies				
27	86 MW Solar	155	561.6		
28	10 MW Solar	178	561.6		
29	100 MW Solar	223	561.6		
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	System Impact Studies				
3	Add Smith DNR	145	561.6	145	561.6
4					
5					
6					
7					
8					
9					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	ASC 715 - Pension and Postretirement (Ongoing)	142,958,558	21,272,089	228	36,998,686	127,231,961
2	KPSC 2003-00434					
3	KPSC 2008-00251					
4	KPSC 2009-00548					
5	KPSC 2012-00221					
6	KPSC 2014-00371					
7	KPSC 2016-00370					
8	FERC AI04-2-000					
9	FERC AI07-1-000					
10						
11	ARO-Generation-Coal Combustion Residuals	131,027,002	27,382,283	407	1,271,174	157,138,111
12	KPSC 2003-00427					
13	KPSC 2003-00434					
14	KPSC 2008-00251					
15	KPSC 2009-00548					
16	KPSC 2012-00221					
17	KPSC 2014-00371					
18	KPSC 2016-00026					
19	KPSC 2016-00370					
20	FERC FA 12-12-000					
21	FERC ER17-234-000					
22						
23	ASC 740 - Income Taxes (Ongoing)	69,916,510	119,154	Various	32,980,368	37,055,296
24	KPSC 2009-00548					
25	KPSC 2012-00221					
26	KPSC 2014-00371					
27	KPSC 2016-00370					
28	KPSC 2018-00034					
29						
30	Forward Starting Swaps Losses (Sep-15 to Oct-45)	40,667,886		427	2,391,436	38,276,450
31	KPSC 2014-00082					
32	KPSC 2014-00371					
33	KPSC 2016-00370					
34						
35	Winter Storm 2009 (Aug-10 to Jul-20)	20,509,839		571/593	5,723,676	14,786,163
36	KPSC 2009-00174					
37	KPSC 2009-00548					
38	KPSC 2012-00221					
39	KPSC 2014-00371					
40	KPSC 2016-00370					
41						
42						
43						
44	TOTAL	443,231,695	68,525,236		94,809,306	416,947,625

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets	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	Asset Retirement Obligation (Ongoing)	10,321,749	6,273,918	230	390,810	16,204,857
2	KPSC 2003-00427					
3	KPSC 2003-00434					
4	KPSC 2008-00251					
5	KPSC 2009-00548					
6	KPSC 2012-00221					
7	KPSC 2014-00371					
8	KPSC 2016-00370					
9	FERC FA 12-12-000					
10	FERC ER08-1588-000					
11	VSCC PUE 2011-00013					
12	VSCC PUE 2013-00013					
13	VSCC PUE 2015-00063					
14						
15	Municipal Formula Rate True-Up (Ongoing)	10,271,668	724,598	447	5,322,877	5,673,389
16	FERC ER-13-2428					
17						
18	Pension Gain/Loss Amortization - 15 Year (Ongoing)	8,845,813	7,041,481	926	1,507,809	14,379,485
19	KPSC 2014-00371					
20	KPSC 2016-00370					
21						
22	Green River Retirement (Ongoing)	3,874,573		Various	1,995,992	1,878,581
23	KPSC 2014-00371					
24	KPSC 2016-00370					
25						
26	2016 Rate Case Expenses (Ongoing)	2,311,440	798,029	928	317,297	2,792,172
27	KPSC 2016-00370					
28						
29	2014 Rate Case Expenses (Jul-15 to Jun-18)	956,492		928	637,661	318,831
30	KPSC 2014-00371					
31	KPSC 2016-00370					
32						
33	Wind Storm 2008 (Aug-10 to Jul-20)	786,727		593	219,552	567,175
34	KPSC 2008-00457					
35	KPSC 2009-00548					
36	KPSC 2012-00221					
37	KPSC 2014-00371					
38	KPSC 2016-00370					
39						
40	Mountain Storm 2009 (Nov-11 to Dec-17)	472,826		593	472,826	
41	VSCC PUE 2011-00013					
42	VSCC PUE 2013-00013					
43	VSCC PUE 2015-00063					
44	TOTAL	443,231,695	68,525,236		94,809,306	416,947,625

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets	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	MISO Exit Fee - FERC (Jul-15 to Jun-17)	148,415	188,528	440-445	336,943	
2	FERC ER13-2428-000					
3	FERC EL14-5-000					
4	FERC EC06-4-000					
5	FERC EC06-4-001					
6	FERC ER06-20-000					
7	FERC ER06-20-001					
8						
9	Carbon Mgmt Research Group (Aug-10 to Jul-20)	162,197	448,880	930	448,880	162,197
10	KPSC 2008-00308					
11	KPSC 2009-00548					
12	KPSC 2012-00221					
13	KPSC 2014-00371					
14	KPSC 2016-00370					
15						
16	Environmental Cost Recovery (Ongoing)		3,597,000	440-445	3,597,000	
17	KRS 278.183					
18						
19	DSM Cost Recovery - Under-Recovery (Ongoing)		679,276	440-445	196,319	482,957
20	KRS 278.285					
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44	TOTAL	443,231,695	68,525,236		94,809,306	416,947,625

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 18 Column: a

Amortization period for closed plants is from July 2016 through June 2026 and amortization period for open plants is from July 2016 through June 2041.

Schedule Page: 232 Line No.: 21 Column: a

Amortization period for closed plants is from January 2017 through April 2019 and amortization period for open plants is from January 2017 through December 2041.

Schedule Page: 232 Line No.: 23 Column: d

Accounts credited include 190, 282 and 283.

Schedule Page: 232 Line No.: 23 Column: e

The balance includes $31,006,764 adjustments due to Tax Reform. Please see Footnote 3, Income and Other Taxes, within the Notes to Financial Statements for additional detail.

Schedule Page: 232.1 Line No.: 22 Column: d

Accounts credited include 408, 500-502, 505-506, 510-514, 925 and 926.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Key Man Life Insurance	34,570,503	1,736,370	131	3,670,781	32,636,092
2						
3	Cane Run 7 LTPC Asset	11,691,712	3,196,833	107, 553	6,065,714	8,822,831
4						
5	Brown 6 and 7 LTPC Asset		3,337,435			3,337,435
6						
7	Long-Term Customer Accounts					
8	Receivable	41,548	94,457	142	64,659	71,346
9						
10	Financing Expense	89,435	49,052	181, 923	83,908	54,579
11						
12	Carrollton Sale/Leaseback					
13	(Aug-06 to Jul-23)	29,043		931	4,412	24,631
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47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	46,422,241				44,946,914

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Net Operating Loss	79,403,823	12,896,184
3	Other Post Retirement & Employment Benefits	21,799,275	14,207,880
4	Regulatory Tax Adjustments	64,576,980	202,593,032
5	Coal Combustion Residual ARO	97,808,158	48,580,719
6	Excess Deferred Taxes - TCJA		53,924,611
7	Other - See Notes for Detail	55,269,717	29,828,278
8	TOTAL Electric (Enter Total of lines 2 thru 7)	318,857,953	362,030,704
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	508,281	340,471
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	319,366,234	362,371,175

Notes

	Bal. at Beg. of Year	Bal. at End of Year
VA Fuel Clause	$ 668,691	$ 220,334
Workers' Compensation	773,877	880,667
Environmental Cost Recovery	266,854	287,773
Vacation Pay	1,941,136	1,274,998
State Tax Adjustment	85,383	369,726
Bad Debt Reserve	687,970	380,468
Demand Side Management	569,652	(124,313)
Pensions	13,853,547	(2,019,686)
Interest Rate Swaps	14,993,446	9,552,077
Air Permit Fees	497,261	626,393
Solar Credit Carryforward	4,601,305	4,611,755
Asset Retirement Obligation	14,486,126	11,889,891
Other	1,844,469	1,878,195
Total Line No. 7	$ 55,269,717	$ 29,828,278

	Bal. at Beg. of Year	Bal. at End of Year
Other Deductions	$ 508,281	$ 340,471
Total Line No. 17	$ 508,281	$ 340,471

Balance of Beginning of Year	$319,366,234
Less Debits to:	
Account 410.1	117,901,921
Account 410.2	185,521
Plus Credits to:	
Account 411.1	23,058,621
Account 411.2	17,711
Other Balance Sheet Accounts	138,016,051
Balance at End of Year	$362,371,175

Note: This year beginning balance will not tie to last year Form 1 due to eliminating purchase accounting.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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.

Additionally, some beginning balance amounts were reordered from prior years' Form 1 ending balance amounts for presentation purposes.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock			
2	Common Stock, Without Par Value	80,000,000		
3	Total Common	80,000,000		
4				
5	Preferred and Preference Stock			
6	Preferred Stock, Without Par Value	5,300,000		
7	Preference Stock, Without Par Value	2,000,000		
8	Total Preferred and Preference	7,300,000		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
37,817,878	308,139,978					2
37,817,878	308,139,978					3
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 250 Line No.: 2 Column: d

There is no call price for common stock, without par value.

Schedule Page: 250 Line No.: 3 Column: a

The common stock of KU is owned by its parent company, LKE.

Schedule Page: 250 Line No.: 8 Column: a

No shares of preferred or preference stock remain issued or outstanding.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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. Balance January 1, 2017	583,858,083
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40	TOTAL	583,858,083

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	321,289
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22	TOTAL	321,289

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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:		
2	Pollution Control Bonds:		
3	Mercer County 2000 Series A, due 05/01/2023, Variable	12,900,000	607,408
4	Carroll County 2002 Series A, due 02/01/2032, Variable	20,930,000	120,138
5	Carroll County 2002 Series B, due 02/01/2032, Variable	2,400,000	83,078
6	Mercer County 2002 Series A, due 02/01/2032, Variable	7,400,000	92,678
7	Muhlenberg County 2002 Series A, due 02/01/2032, Variable	2,400,000	93,078
8	Carroll County 2004 Series A, due 10/01/2034, Variable	50,000,000	1,483,449
9	Carroll County 2006 Series B, due 10/01/2034, Variable	54,000,000	1,315,275
10	Carroll County 2007 Series A, due 02/01/2026, 5.750%	17,875,000	638,428
11	Trimble County 2007 Series A, due 03/01/2037, 6.000%	8,927,000	471,138
12	Carroll County 2008 Series A, due 02/01/2032, Variable	77,947,405	798,036
13	Carroll County 2016 Series A, due 09/01/2042, 1.050%	96,000,000	897,648
14			
15	First Mortgage Bonds:		
16	2010 due 11/01/2020, 3.250%	500,000,000	4,156,684
17			1,890,000 D
18	2010 due 11/01/2040, 5.125%	750,000,000	7,480,434
19			8,137,500 D
20	2013 due 11/15/2043, 4.650%	250,000,000	2,773,770
21			1,800,000 D
22	2015 due 10/1/2025, 3.300%	250,000,000	2,014,576
23			107,500 D
24	2015 due 10/1/2045, 4.375%	250,000,000	2,577,076
25			207,500 D
26	TOTAL ACCOUNT 221	2,350,779,405	37,745,394
27			
28	ACCOUNT 223:		
29	TOTAL ACCOUNT 223		
30			
31			
32	ACCOUNT 224:		
33	TOTAL	2,350,779,405	37,745,394

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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			
3			
4	TOTAL ACCOUNT 224		
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	2,350,779,405	37,745,394

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
05/19/2000	05/01/2023	05/19/2000	05/01/2023	12,900,000	115,603	3
05/23/2002	02/01/2032	05/23/2002	02/01/2032	20,930,000	197,308	4
05/23/2002	02/01/2032	05/23/2002	02/01/2032	2,400,000	22,641	5
05/23/2002	02/01/2032	05/23/2002	02/01/2032	7,400,000	68,404	6
05/23/2002	02/01/2032	05/23/2002	02/01/2032	2,400,000	22,509	7
10/20/2004	10/01/2034	10/20/2004	10/01/2034	50,000,000	448,821	8
02/23/2007	10/01/2034	02/23/2007	10/01/2034	54,000,000	483,516	9
05/24/2007	02/01/2026	05/24/2007	02/01/2026	17,875,000	1,027,813	10
05/24/2007	03/01/2037	05/24/2007	03/01/2037	8,927,000	535,620	11
10/17/2008	02/01/2032	10/17/2008	02/01/2032	77,947,405	701,597	12
08/25/2016	09/01/2042	08/25/2016	09/01/2042	96,000,000	1,008,000	13
						14
						15
11/16/2010	11/01/2020	11/16/2010	11/1/2020	500,000,000	16,250,000	16
						17
11/16/2010	11/01/2040	11/16/2010	11/01/2040	750,000,000	38,437,500	18
						19
11/14/2013	11/15/2043	11/14/2013	11/15/2043	250,000,000	10,191,296	20
						21
09/28/2015	10/1/2025	09/28/2015	10/01/2025	250,000,000	9,655,380	22
						23
09/28/2015	10/1/2045	09/28/2015	10/1/2045	250,000,000	11,923,556	24
						25
				2,350,779,405	91,089,564	26
						27
						28
						29
						30
						31
						32
				2,350,779,405	91,089,564	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
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						26
						27
						28
						29
						30
						31
						32
				2,350,779,405	91,089,564	33

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 1 Column: a

Per instruction 9 concerning the treatment of unamortized debt expense, premium or discount, original debt premium and expenses are being amortized over the lives of the related issues and remarketing expenses are being amortized through the put dates of the remarketed bonds.

Schedule Page: 256 Line No.: 2 Column: a

Pollution control series bonds are obligations of KU, issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates KU to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds.

Schedule Page: 256 Line No.: 15 Column: a

Proceeds from KU's First Mortgage Bonds issued in 2010 were used to repay the loans from a PPL subsidiary and for general corporate purposes. Proceeds from KU's First Mortgage Bonds issued in 2013 were used for capital expenditures and general corporate purposes. Proceeds from KU's First Mortgage Bonds issued in 2015 were used to pay maturing debt, pay down short term debt, and general corporate purposes. The First Mortgage Bonds were issued at a discount.

As of December 31, 2017, 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.

Schedule Page: 256 Line No.: 28 Column: a

KU did not have long-term notes with associated companies in 2017.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	257,108,756
2		
3		
4	Taxable Income Not Reported on Books	
5	See Footnote	10,894,699
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Footnote	186,471,030
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Footnote	10,693,994
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Footnote	443,780,491
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	
28	Show Computation of Tax:	
29		
30	Federal Tax Net Income	
31	35% Rounded	
32	Add: Adjustments to Prior Years' Taxes to Actual and Other	-39
33		
34	Total	-39
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 5 Column: b

Contributions in Aid of Construction	$ 3,250,000
Environmental Cost Recovery	432,000
Muni True-Up Regulatory Asset	4,598,279
Refined Coal Regulatory Liability	2,614,420
Total	$ 10,894,699

Schedule Page: 261 Line No.: 10 Column: b

Federal Income Taxes:	
Utility Operating Income	$ 971,580
Provision for Deferred Income Taxes	152,993,738
Amortization Loss on Reacquired Debt	610,000
Contingent Liabilities	1,155,234
Current State Income Tax	1,516,647
Capitalized Interest	11,025,000
EEI Investment	2,967,600
Amortization of Regulatory Asset/Liability Associated with Net Forward Starting Swaps	957,732
Green River Regulatory Asset	1,995,992
Plant Outage Normalizaton - Regulatory Liability	1,220,138
Postemployment	1,129,081
Non-Deductible Expenses	681,757
AFUDC Flow Through	890,563
Amortization of Regulatory Assets Associated with Storms	6,416,054
Workers Compensation	1,431,992
Other	507,922
Total	$ 186,471,030

Schedule Page: 261 Line No.: 15 Column: b

Fuel Adjustment Clause KY	$ 5,957,000
Demand Side Management	1,947,358
Over/Under Collections - VA Fuel Clause	863,000
Amortization of Investment Tax Credit	1,926,636
Total	$ 10,693,994

Schedule Page: 261 Line No.: 20 Column: b

Federal Income Taxes:	
Other Income and Deductions	$ 971,619
Tax Over Book Depreciation, Net and Repairs	188,036,879
Deferred Operating	1,311,398
Cost of Removal	22,010,191
Net Operating Loss Carryforward	169,924,645
Postretirement	3,157,126
Pensions	35,274,976
Coal Combustion Residual ARO	18,878,527
Life Insurance	2,655,243
Customer Advances for Construction	678,918
Other	880,969
Total	$ 443,780,491

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	29,176,977		162,352	29,339,329	
3	FICA	610,508		6,586,089	6,562,063	
4						
5	Kentucky:					
6	Income	243,952		6,634,717	5,118,070	
7	Public Service Commission		1,565,917	3,208,618	3,285,403	
8	Use	755,337		6,347,232	6,161,250	
9						
10	Federal & Kentucky:					
11	Unemployment Insurance	25,704		96,593	103,602	
12						
13	Kentucky & Virginia:					
14	Property Taxes	14,311,629		28,846,438	27,683,294	
15	Miscellaneous			66,228	66,228	
16						
17	Virginia Use	3		18,878	13,259	
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	45,124,110	1,565,917	51,967,145	78,332,498	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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
		971,580			-809,228	2
634,534		9,610,926			-3,024,837	3
						4
						5
1,760,599		6,811,912			-177,195	6
	1,642,702	3,208,618				7
941,319		24,358			6,322,874	8
						9
						10
18,695		203,730			-107,137	11
						12
						13
15,474,773		28,406,721			439,717	14
		66,228				15
						16
5,622					18,878	17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
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						29
						30
						31
						32
						33
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						35
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						38
						39
						40
18,835,542	1,642,702	49,304,073			2,663,072	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 1 Column: a

Segregation of Other	Other (1)	Page 117 Other Inc & Deductions 408.2 - 409.2	Other Accounts
Federal:			
Income	$ (809,228)	$ (971,619)	$ 162,391
FICA	(3,024,837)	-	(3,024,837)
Kentucky:			
Income	(177,195)	(177,195)	(0)
6% Use	6,322,874	-	6,322,874
Federal & Kentucky:			
Unemployment Ins	(107,137)	-	(107,137)
Kentucky & Virgina:			
Property Taxes	439,717	11,133	428,584
Virginia Use	18,878	-	18,878
Total	$ 2,663,072	$ (1,137,681)	$ 3,800,753

Reconciliation to Schedule Page: 114, Line No.: 14, Column: c

Other:	
Electric Total	$ 49,304,073
Less Federal Income	(971,580)
Less State Income	(6,811,912)
Total	$ 41,520,581

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	15%	88,755,164			420	1,864,820	
7	Various	7,018,876	411.4	10,450	420	61,816	
8	TOTAL	95,774,040		10,450		1,926,636	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13	Total						
14							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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
86,890,344	52 years		6
6,967,510	25 and 52 years		7
93,857,854			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
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			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Corporate Headquarters Lease					
2	(Jul-12 to Dec-25)	1,306,173	931	4,945		1,301,228
3						
4	Deferred Rent Payable					
5	(Aug-06 to Jul-23)	34,577	931	5,256		29,321
6						
7	Deferred Compensation	10,834			16,097	26,931
8						
9	Carrollton Sale/Leaseback					
10	(Aug-06 to Jul-23)	28,842	421.1	4,381		24,461
11						
12	Uncertain Tax Position - Federal	162,391	236	162,391		
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
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46						
47	TOTAL	1,542,817		176,973	16,097	1,381,941

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
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	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. 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
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	1,328,098,043	211,799,257	158,888,252
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,328,098,043	211,799,257	158,888,252
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,328,098,043	211,799,257	158,888,252
10	Classification of TOTAL			
11	Federal Income Tax	1,184,386,467	181,208,381	137,933,308
12	State Income Tax	143,711,576	30,590,876	20,954,944
13	Local Income Tax			

NOTES

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. 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
		182/254	539,496,960	182/254	62,079,482	903,591,570	2
							3
							4
			539,496,960		62,079,482	903,591,570	5
							6
							7
							8
			539,496,960		62,079,482	903,591,570	9
							10
			539,304,526		61,534,778	749,891,792	11
			192,434		544,704	153,699,778	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: b

The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2016, is $10,470,966 and the Coal Combustion Residual ARO balance is $50,550,763.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2016, is $37,062,344.

Schedule Page: 274 Line No.: 2 Column: k

The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2017, is $7,718,761 and the Coal Combustion Residual ARO balance is $15,448,992.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2017, is ($440,355,134). Please see Footnote 3, Income and Other Taxes, within the Notes to Financial Statements for additional detail.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Regulatory Tax Adjustments	27,197,523		
4	Interest Rate Swaps	15,819,808	50,220	980,489
5	Excess Deferred Taxes - TCJA			
6	Pension - Regulatory Asset	47,241,520	3,671,004	6,080,989
7	Coal Combustion Residual ARO	50,969,504	10,705,555	548,333
8	Other	20,275,368	8,480,987	9,071,935
9	TOTAL Electric (Total of lines 3 thru 8)	161,503,723	22,907,766	16,681,746
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other			
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	161,503,723	22,907,766	16,681,746
20	Classification of TOTAL			
21	Federal Income Tax	136,593,123	19,552,459	14,169,211
22	State Income Tax	24,910,600	3,355,307	2,512,535
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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
		182	19,198,738	182	1,539,248	9,538,033	3
		254	5,037,181			9,852,358	4
				254	48,046,768	48,046,768	5
		254	15,670,906			29,160,629	6
		254	20,679,376			40,447,350	7
		254	6,659,305			13,025,115	8
			67,245,506		49,586,016	150,070,253	9
							10
							11
							12
							13
							14
							15
							16
							17
1,722,948	2,877,345	219	1,722,948	219	2,877,345		18
1,722,948	2,877,345		68,968,454		52,463,361	150,070,253	19
							20
1,722,948	2,699,289		66,951,666		52,240,191	126,288,555	21
	178,056		2,016,788		223,170	23,781,698	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 8 Column: b

Rate Case Expenses	$ 1,271,226
FAC Over/Under-Recovery	(3,470,659)
Other	817,827
Loss on Reacquired Debt	3,670,630
Green River Regulatory Asset	1,507,209
Muni True-Up Regulatory Asset	3,995,679
Casualty Loss - Storm Damages	8,468,296
Asset Retirement Obligation	4,015,160

Total for Accumulated Deferred Income Taxes - Other (283)	$ 20,275,368

Schedule Page: 276 Line No.: 8 Column: c

Amounts Debited to Account 410.1:	
Rate Case Expenses	$ 653,279
FAC Over/Under-Recovery	4,956,528
Other	173,077
Loss on Reacquired Debt	12,810
Green River Regulatory Asset	41,916
Muni True-Up Regulatory Asset	96,564
Casualty Loss - Storm Damages	134,738
Asset Retirement Obligation	2,412,075

Total for Amounts Debited to Account 410.1	$ 8,480,987

Schedule Page: 276 Line No.: 8 Column: d

Amounts Credited to Account 411.1:	
Rate Case Expenses	$ 714,324
FAC Over/Under-Recovery	2,639,255
Other	10,478
Loss of Reacquired Debt	250,100
Green River Regulatory Asset	818,357
Muni True-Up Regulatory Asset	1,885,294
Casualty Loss - Storm Damages	2,630,582
Asset Retirement Obligation	123,545

Total for Amounts Credited to Account 411.1	$ 9,071,935

Schedule Page: 276 Line No.: 8 Column: h

Rate Case Expenses	$ 409,408
FAC Over/Under-Recovery	(390,194)
Other	331,682
Loss on Reacquired Debt	1,161,510
Green River Regulatory Asset	247,221
Muni True-Up Regulatory Asset	746,618
Casualty Loss - Storm Damages	2,020,500
Asset Retirement Obligation	2,132,560

Total for Accumulated Deferred Income Taxes - Other (283)	$ 6,659,305

Schedule Page: 276 Line No.: 8 Column: k

Rate Case Expenses	$ 800,773
FAC Over/Under-Recovery	(763,192)
Other	648,744
Loss on Reacquired Debt	2,271,830
Green River Regulatory Asset	483,547
Muni True-Up Regulatory Asset	1,460,331
Casualty Loss - Storm Damages	3,951,952

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Asset Retirement Obligation	4,171,130

Total for Accumulated Deferred Income Taxes - Other (283)	$ 13,025,115

Schedule Page: 276 Line No.: 9 Column: b

This year beginning balance will not tie to last year Form 1 due to eliminating purchase accounting. Additionally, some beginning balance amounts were reordered from prior years' Form 1 ending balance amounts for presentation purposes.

Schedule Page: 276 Line No.: 18 Column: e

Amounts Debited to Account 410.2:

EEI Investment $ 1,722,948

Schedule Page: 276 Line No.: 18 Column: f

Amounts Credited to Account 411.2:

EEI Investment $ 2,877,345

Schedule Page: 276 Line No.: 18 Column: h

Debit Adjustments:

OCI EEI Investment $ 1,722,948

Schedule Page: 276 Line No.: 18 Column: j

Credit Adjustments:

OCI EEI Investment $ 2,877,345

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	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	ASC 740 - Income Taxes (Ongoing)	70,233,624	190/282	2,702,193	602,933,998	670,465,429
2	KPSC 2005-00181					
3	KPSC 2006-00456					
4	KPSC 2009-00548					
5	KPSC 2012-00221					
6	KPSC 2014-00371					
7	KPSC 2016-00370					
8	KPSC 2018-00034					
9						
10	Forward Starting Swaps Gains (Sep-15 to Oct-45)	38,543,562	427	1,433,704		37,109,858
11	KPSC 2012-00232					
12	KPSC 2012-00221					
13	KPSC 2014-00371					
14	KPSC 2016-00370					
15						
16	ASC 715 - Pension and Postretirement (Ongoing)	22,795,270	184/228	10,731,849	15,309,192	27,372,613
17	KPSC 2003-00434					
18	KPSC 2008-00251					
19	KPSC 2009-00548					
20	KPSC 2012-00221					
21	KPSC 2014-00371					
22	KPSC 2016-00370					
23	FERC AI04-2-000					
24	FERC AI07-1-000					
25						
26	KY Fuel Adjustment Clause (Ongoing)	8,922,000	440-445	11,936,000	5,979,000	2,965,000
27	807 KAR 5:056					
28						
29	VA Fuel Component (Ongoing)	1,539,000	440-442	769,000		770,000
30	Title 56 of the Code of Virginia,					
31	Chapter 10; Section 56-249.6					
32						
33	DSM Cost Recovery (Ongoing)	1,464,401	440-445	1,956,541	492,140	
34	KRS 278.285					
35						
36	Environmental Cost Recovery (Ongoing)	686,000	440-445	3,073,000	3,505,000	1,118,000
37	KRS 278.183					
38						
39						
40						
41	TOTAL	145,201,851		37,948,470	637,056,470	744,309,851

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	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	Refined Coal - Kentucky (Ongoing)	558,325	454/456/501	4,670,606	6,995,166	2,882,885
2	KPSC 2015-00264					
3	KPSC 2016-00370					
4	FERC EL 15-92-000					
5						
6	Refined Coal - Virginia	23,848			289,861	313,709
7	Requested Jul-18 to Jun-22					
8	PUR 2017-00106					
9						
10	VA Fuel Component - Non-Jurisdictional (Ongoing)	180,000	445	94,000		86,000
11	Title 56 of the Code of Virginia,					
12	Chapter 10; Section 56-249.6					
13						
14	MISO Exit Fee Refund - KY (Jul-15 to Jun-17)	166,313	575	166,313		
15	KPSC 2003-00266					
16	KPSC 2008-00251					
17	KPSC 2012-00221					
18	KPSC 2014-00371					
19	FERC EC06-4-000					
20	FERC EC06-4-001					
21	FERC ER06-20-000					
22	FERC ER06-20-001					
23						
24	Off-System Sales Tracker (Ongoing)	89,508	440-445	415,264	331,975	6,219
25	KPSC 2014-00371					
26	KPSC 2016-00370					
27	807 KAR 5:056					
28						
29	Plant Outage Normalization (Ongoing)				1,220,138	1,220,138
30	KPSC 2016-00370					
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	145,201,851		37,948,470	637,056,470	744,309,851

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 278 Line No.: 1 Column: e

The balance includes $602,927,345 adjustments due to Tax Reform. Please see Footnote 3, Income and Other Taxes, within the Notes to Financial Statements for additional detail.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	622,194,583	633,811,482
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	400,741,032	391,730,928
5	Large (or Ind.) (See Instr. 4)	416,443,589	415,695,730
6	(444) Public Street and Highway Lighting	13,144,391	12,980,249
7	(445) Other Sales to Public Authorities	131,177,842	131,374,630
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,583,701,437	1,585,593,019
11	(447) Sales for Resale	124,898,398	134,026,710
12	TOTAL Sales of Electricity	1,708,599,835	1,719,619,729
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	1,708,599,835	1,719,619,729
15	Other Operating Revenues		
16	(450) Forfeited Discounts	3,864,385	3,920,889
17	(451) Miscellaneous Service Revenues	2,262,170	2,162,364
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	7,211,409	3,275,385
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	251,590	308,734
22	(456.1) Revenues from Transmission of Electricity of Others	22,143,690	20,048,998
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	35,733,244	29,716,370
27	TOTAL Electric Operating Revenues	1,744,333,079	1,749,336,099

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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
6,039,478	6,416,653	452,920	449,845	2
				3
3,963,535	4,041,728	84,818	84,259	4
6,601,696	6,733,922	2,736	2,921	5
45,330	45,166	1,481	1,485	6
1,578,699	1,643,895	8,681	8,559	7
				8
				9
18,228,738	18,881,364	550,636	547,069	10
2,269,059	2,556,599	21	24	11
20,497,797	21,437,963	550,657	547,093	12
				13
20,497,797	21,437,963	550,657	547,093	14

Line 12, column (b) includes $ 25,834,287 of unbilled revenues.
Line 12, column (d) includes 90,671 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 300 Line No.: 22 Column: b

Items which compose Revenues from Transmission of Electricity of Others (456.1) year-to-date activity:

Owensboro Municipal Utilities	$ 6,294,382
East Kentucky Power Cooperative	6,127,649
Kentucky Municipal Power Agency	1,997,525
City of Frankfort	1,756,794
Tennessee Valley Authority	1,087,948
Midcontinent Independent System Operator	1,037,034
City of Madisonville	716,251
Louisville Gas & Electric Company	621,437
City of Bardstown	488,552
City of Nicholasville	481,963
City of Berea	334,309
Other items less than $250,000 each	1,199,846
Total for Revenues from Transmission of Electricity of Others (456.1)	$ 22,143,690

Schedule Page: 300 Line No.: 22 Column: c

Items which compose Revenues from Transmission of Electricity of Others (456.1) year-to-date activity:

Owensboro Municipal Utilities	$ 5,598,014
East Kentucky Power Cooperative	5,033,626
Kentucky Municipal Power Agency	1,992,093
City of Frankfort	1,679,881
Midcontinent Independent System Operator	1,160,717
Tennessee Valley Authority	884,063
City of Madisonville	685,761
Louisville Gas and Electric Company	517,320
City of Nicholasville	468,314
City of Bardstown	461,175
City of Berea	314,527
Other items less than $250,000 each	1,253,507
Total for Revenues from Transmission of Electricity of Others (456.1)	$ 20,048,998

Schedule Page: 300 Line No.: 1 Column: $

The net unbilled revenue represents the following:

Base Revenue	$ 17,412,000
Environmental Cost Recovery Accrual	(432,000)
Fuel Adjustment Clause Accrual	5,957,000
Demand Side Management Accrual	1,950,998
Levelized Fuel Factor Accrual	863,000
Off-System Sales Tracker Accrual	83,289
Net Unbilled	$ 25,834,287

Schedule Page: 300 Line No.: 1 Column: MWH

Unbilled revenue of 90,671 MWH represents the net change of unbilled MWH from the previous period; as a result, it could be positive or negative.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (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					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 440					
2	Residential Service - KY	5,620,621	569,182,316	427,815	13,138	0.1013
3	Residential Time-of-Day - E - KY	291	28,519	27	10,778	0.0980
4	Volunteer Fire Department - KY	116	11,513	8	14,500	0.0993
5	General Service - KY	961	124,010	1,648	583	0.1290
6	Lighting Service - KY	20,599	4,704,988	37,280	553	0.2284
7	Restricted Lighting Service - KY	2,935	527,128	3,661	802	0.1796
8	Residential Service - TN	77	5,556	3	25,667	0.0722
9	Lighting Service - TN	1	193	2	500	0.1930
10	Residential Service - VA	334,050	33,868,863	23,404	14,273	0.1014
11	General Service - VA	43	6,924	220	195	0.1610
12	Private Outdoor Lighting - VA	2,882	796,975	4,633	622	0.2765
13	Street Lighting - VA	4	1,015	4	1,000	0.2538
14	Duplicate Customers			-45,785		
15						
16	Reclassifications and Adjustments		-26,010			
17						
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37						
38	Subtotal	5,982,580	609,231,990	452,920	13,209	0.1018
39	Unbilled	56,898	12,962,593			0.2278
40	Total	6,039,478	622,194,583	452,920	13,335	0.1030
41	TOTAL Billed	18,138,067	1,557,867,150	550,636	32,940	0.0859
42	Total Unbilled Rev.(See Instr. 6)	90,671	25,834,287	0	0	0.2849
43	TOTAL	18,228,738	1,583,701,437	550,636	33,105	0.0869

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 442					
2	Residential Service - KY	423	42,626	309	1,369	0.1008
3	Volunteer Fire Department - KY	75	7,535	5	15,000	0.1005
4	General Service - KY	1,587,294	196,583,883	75,450	21,038	0.1238
5	All Electric School - KY	15,163	1,311,118	98	154,724	0.0865
6	Power Service - KY	1,693,198	154,701,771	4,066	416,428	0.0914
7	Time-of-Day Secondary - KY	1,540,811	112,520,567	540	2,853,354	0.0730
8	Time-of-Day Primary - KY	3,343,576	209,042,028	204	16,390,078	0.0625
9	Retail Transmission Service - KY	1,410,016	78,297,325	25	56,400,640	0.0555
10	Fluctuating Load Service - KY	606,960	17,167,861	1	606,960,000	0.0283
11	Lighting Service - KY	39,593	7,723,217	17,464	2,267	0.1951
12	Restricted Lighting Service - KY	8,296	1,680,487	3,059	2,712	0.2026
13	Lighting Energy - KY	56	3,928	5	11,200	0.0701
14	Traffic Energy Service - KY	381	46,313	388	982	0.1216
15	Elec Vehicle Charging Svc - KY	1	712	2	500	0.7120
16	School Power Service - KY	1,206	118,215	4	301,500	0.0980
17	School Time-of-Day Service - KY	1,511	127,753	2	755,500	0.0845
18	Outdoor Sports Lighting Svc - KY	58	14,231	2	29,000	0.2454
19	Special Contract - KY		96,326	1		
20	Residential Service - VA	96	9,663	91	1,055	0.1007
21	General Service - VA	63,773	7,477,371	3,410	18,702	0.1172
22	Power Service - VA	126,947	10,649,004	166	764,741	0.0839
23	Time-of-Day Secondary - VA	21,061	1,643,616	8	2,632,625	0.0780
24	Time-of-Day Primary - VA	59,301	5,482,837	6	9,883,500	0.0925
25	Retail Transmission Service - VA	16,308	1,274,781	3	5,436,000	0.0782
26	Private Outdoor Lighting - VA	1,222	321,255	847	1,443	0.2629
27	Street Lighting - VA	1	193	4	250	0.1930
28	School Service - VA	304	27,458	5	60,800	0.0903
29	Duplicate Customers			-18,611		
30						
31	Reclassifications and Adjustments		46,038			
32						
33						
34						
35						
36						
37						
38	Subtotal	10,537,631	806,418,112	87,554	120,356	0.0765
39	Unbilled	27,600	10,766,509			0.3901
40	Total	10,565,231	817,184,621	87,554	120,671	0.0773
41	TOTAL Billed	18,138,067	1,557,867,150	550,636	32,940	0.0859
42	Total Unbilled Rev.(See Instr. 6)	90,671	25,834,287	0	0	0.2849
43	TOTAL	18,228,738	1,583,701,437	550,636	33,105	0.0869

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 444					
2	Residential Service - KY	16	1,732	1	16,000	0.1083
3	General Service - KY	1,202	233,421	653	1,841	0.1942
4	Lighting Service - KY	33,133	10,280,752	1,089	30,425	0.3103
5	Restricted Lighting Service - KY	8,318	1,932,509	201	41,383	0.2323
6	Lighting Energy - KY	40	2,800	1	40,000	0.0700
7	Traffic Energy Service - KY	793	88,243	300	2,643	0.1113
8	General Service - VA	28	4,528	5	5,600	0.1617
9	Private Outdoor Lighting - VA	1	313	14	71	0.3130
10	Street Lighting - VA	1,594	404,777	47	33,915	0.2539
11	Duplicate Customers			-830		
12						
13	Reclassifications and Adjustments		-2,369			
14						
15						
16						
17						
18						
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24						
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26						
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37						
38	Subtotal	45,125	12,946,706	1,481	30,469	0.2869
39	Unbilled	205	197,685			0.9643
40	Total	45,330	13,144,391	1,481	30,608	0.2900
41	TOTAL Billed	18,138,067	1,557,867,150	550,636	32,940	0.0859
42	Total Unbilled Rev.(See Instr. 6)	90,671	25,834,287	0	0	0.2849
43	TOTAL	18,228,738	1,583,701,437	550,636	33,105	0.0869

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 445					
2	Residential Service - KY	3,306	375,272	521	6,345	0.1135
3	Volunteer Fire Department - KY	922	89,318	40	23,050	0.0969
4	General Service - KY	137,447	16,910,460	5,390	25,500	0.1230
5	All Electric School - KY	121,890	10,366,408	459	265,556	0.0850
6	Power Service - KY	301,753	29,467,786	704	428,626	0.0977
7	Time-of-Day Service Secondary- KY	193,242	16,190,631	122	1,583,951	0.0838
8	Time-of-Day Service Primary - KY	663,983	41,815,429	47	14,127,298	0.0630
9	Retail Transmission Service - KY	24,864	1,412,568	1	24,864,000	0.0568
10	Lighting Service - KY	9,070	2,030,861	2,218	4,089	0.2239
11	Restricted Lighting Service - KY	557	46,182	390	1,428	0.0829
12	Lighting Energy - KY	478	33,528	6	79,667	0.0701
13	Traffic Energy Service - KY	400	39,220	88	4,545	0.0981
14	School Power Service - KY	11,903	1,202,731	28	425,107	0.1010
15	School Time-of-Day Service - KY	33,675	2,832,549	28	1,202,679	0.0841
16	Outdoor Sports Lighting Svc - KY	23	3,582	1	23,000	0.1557
17	Residential Service - VA	422	47,181	61	6,918	0.1118
18	General Service - VA	13,191	1,526,942	670	19,688	0.1158
19	Power Service - VA	26,980	2,210,942	36	749,444	0.0819
20	Time-of-Day Secondary - VA	1,383	123,788	1	1,383,000	0.0895
21	Time-of-Day Primary - VA	2,503	199,293	1	2,503,000	0.0796
22	Private Outdoor Lighting - VA	708	183,129	236	3,000	0.2587
23	Street Lighting - VA	8	1,998	13	615	0.2498
24	School Service - VA	23,441	2,123,060	129	181,713	0.0906
25	Water Pumping Service - VA	582	35,781	16	36,375	0.0615
26	Duplicate Customers			-2,525		
27						
28	Reclassifications and Adjustments		1,703			
29						
30						
31						
32						
33						
34						
35						
36						
37						
38	Subtotal	1,572,731	129,270,342	8,681	181,169	0.0822
39	Unbilled	5,968	1,907,500			0.3196
40	Total	1,578,699	131,177,842	8,681	181,857	0.0831
41	TOTAL Billed	18,138,067	1,557,867,150	550,636	32,940	0.0859
42	Total Unbilled Rev.(See Instr. 6)	90,671	25,834,287	0	0	0.2849
43	TOTAL	18,228,738	1,583,701,437	550,636	33,105	0.0869

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 304 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $(22,545,117)

Schedule Page: 304 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $(1,130)

Schedule Page: 304 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $(462)

Schedule Page: 304 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $(3,780)

Schedule Page: 304 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $(81,989)

Schedule Page: 304 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $(11,662)

Schedule Page: 304 Line No.: 16 Column: a
Includes current and prior period reclassifications between FERC accounts and net billing adjustments.

Schedule Page: 304.1 Line No.: 2 Column: c
Includes Fuel Adjustment Clause $(1,686)

Schedule Page: 304.1 Line No.: 3 Column: c
Includes Fuel Adjustment Clause $(292)

Schedule Page: 304.1 Line No.: 4 Column: c
Includes Fuel Adjustment Clause $(6,382,339)

Schedule Page: 304.1 Line No.: 5 Column: c
Includes Fuel Adjustment Clause $(60,871)

Schedule Page: 304.1 Line No.: 6 Column: c
Includes Fuel Adjustment Clause $(6,806,244)

Schedule Page: 304.1 Line No.: 7 Column: c
Includes Fuel Adjustment Clause $(6,161,000)

Schedule Page: 304.1 Line No.: 8 Column: c
Includes Fuel Adjustment Clause $(13,434,189)

Schedule Page: 304.1 Line No.: 9 Column: c
Includes Fuel Adjustment Clause $(5,833,411)

Schedule Page: 304.1 Line No.: 10 Column: c
Includes Fuel Adjustment Clause $(2,569,787)

Schedule Page: 304.1 Line No.: 11 Column: c
Includes Fuel Adjustment Clause $(155,974)

Schedule Page: 304.1 Line No.: 12 Column: c
Includes Fuel Adjustment Clause $(30,865)

Schedule Page: 304.1 Line No.: 13 Column: c
Includes Fuel Adjustment Clause $(227)

Schedule Page: 304.1 Line No.: 14 Column: c
Includes Fuel Adjustment Clause $(1,565)

Schedule Page: 304.1 Line No.: 15 Column: c
Includes Fuel Adjustment Clause $(2)

Schedule Page: 304.1 Line No.: 16 Column: c
Includes Fuel Adjustment Clause $(4,189)

Schedule Page: 304.1 Line No.: 17 Column: c
Includes Fuel Adjustment Clause $(5,227)

Schedule Page: 304.1 Line No.: 18 Column: c
Includes Fuel Adjustment Clause $(191)

Schedule Page: 304.1 Line No.: 31 Column: a
Includes current and prior period reclassifications between FERC accounts and net billing adjustments.

Schedule Page: 304.2 Line No.: 2 Column: c
Includes Fuel Adjustment Clause $(65)

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 304.2 Line No.: 3 Column: c
Includes Fuel Adjustment Clause $(4,903)
Schedule Page: 304.2 Line No.: 4 Column: c
Includes Fuel Adjustment Clause $(136,009)
Schedule Page: 304.2 Line No.: 5 Column: c
Includes Fuel Adjustment Clause $(33,877)
Schedule Page: 304.2 Line No.: 6 Column: c
Includes Fuel Adjustment Clause $(172)
Schedule Page: 304.2 Line No.: 7 Column: c
Includes Fuel Adjustment Clause $(3,256)
Schedule Page: 304.2 Line No.: 13 Column: a
Includes current and prior period reclassifications between FERC accounts and net billing adjustments.
Schedule Page: 304.3 Line No.: 2 Column: c
Includes Fuel Adjustment Clause $(13,337)
Schedule Page: 304.3 Line No.: 3 Column: c
Includes Fuel Adjustment Clause $(3,734)
Schedule Page: 304.3 Line No.: 4 Column: c
Includes Fuel Adjustment Clause $(557,876)
Schedule Page: 304.3 Line No.: 5 Column: c
Includes Fuel Adjustment Clause $(491,081)
Schedule Page: 304.3 Line No.: 6 Column: c
Includes Fuel Adjustment Clause $(1,225,137)
Schedule Page: 304.3 Line No.: 7 Column: c
Includes Fuel Adjustment Clause $(799,365)
Schedule Page: 304.3 Line No.: 8 Column: c
Includes Fuel Adjustment Clause $(2,767,000)
Schedule Page: 304.3 Line No.: 9 Column: c
Includes Fuel Adjustment Clause $(97,762)
Schedule Page: 304.3 Line No.: 10 Column: c
Includes Fuel Adjustment Clause $(39,015)
Schedule Page: 304.3 Line No.: 11 Column: c
Includes Fuel Adjustment Clause $(5,144)
Schedule Page: 304.3 Line No.: 12 Column: c
Includes Fuel Adjustment Clause $(2,019)
Schedule Page: 304.3 Line No.: 13 Column: c
Includes Fuel Adjustment Clause $(1,654)
Schedule Page: 304.3 Line No.: 14 Column: c
Includes Fuel Adjustment Clause $(42,186)
Schedule Page: 304.3 Line No.: 15 Column: c
Includes Fuel Adjustment Clause $(119,992)
Schedule Page: 304.3 Line No.: 16 Column: c
Includes Fuel Adjustment Clause $(82)
Schedule Page: 304.3 Line No.: 28 Column: a
Includes current and prior period reclassifications between FERC accounts and net billing adjustments.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	City of Barbourville	RQ	184	17	17	16
2	City of Bardstown	RQ	185	33	33	32
3	City of Bardwell	RQ	186	2	2	1
4	City of Berea	RQ	197	23	23	22
5	City of Corbin	RQ	188	15	15	15
6	City of Falmouth	RQ	189	3	3	3
7	City of Frankfort	RQ	190	116	116	114
8	City of Madisonville	RQ	161	48	48	45
9	City of Nicholasville	RQ	157	33	33	32
10	City of Paris	RQ	83	4	4	3
11	City of Providence	RQ	195	5	5	5
12	Benham Power Board	OS	(9)	N/A	N/A	N/A
13	Cargill Power Markets, LLC	OS	(3)	N/A	N/A	N/A
14	East Kentucky Power Cooperative	OS	(9)	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	ETC Endure Energy, LLC	OS	(3)	N/A	N/A	N/A
2	Illinois Municipal Electric Agency	OS	(5)	N/A	N/A	N/A
3	Illinois Municipal Electric Agency	OS	(6)	N/A	N/A	N/A
4	Illinois Municipal Electric Agency	AD	(6)	N/A	N/A	N/A
5	Illinois Municipal Electric Agency	OS	(8)	N/A	N/A	N/A
6	Indiana Municipal Power Agency	OS	(7)	N/A	N/A	N/A
7	Indiana Municipal Power Agency	OS	(6)	N/A	N/A	N/A
8	Indiana Municipal Power Agency	AD	(6)	N/A	N/A	N/A
9	Indiana Municipal Power Agency	OS	(8)	N/A	N/A	N/A
10	Kentucky Municipal Energy Agency	OS	(9)	N/A	N/A	N/A
11	Kentucky Municipal Power Agency	OS	(9)	N/A	N/A	N/A
12	Louisville Gas and Electric Company	SF	(1)	N/A	N/A	N/A
13	Midcontinent Independent System Oper	OS	(3)	N/A	N/A	N/A
14	Midcontinent Independent System Oper	AD	(3)	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Owensboro Municipal Utilities	OS	(10)	N/A	N/A	N/A
2	Owensboro Municipal Utilities	OS	(9)	N/A	N/A	N/A
3	PJM Settlements, Inc.	OS	(3)	N/A	N/A	N/A
4	Tenaska Power Services Company	OS	(3)	N/A	N/A	N/A
5	Tennessee Valley Authority	OS	(3)	N/A	N/A	N/A
6	The Energy Authority	OS	(10)	N/A	N/A	N/A
7	Westar Energy, Inc.	OS	(3)	N/A	N/A	N/A
8	City of Barbourville	AD	184	N/A	N/A	N/A
9	City of Bardstown	AD	185	N/A	N/A	N/A
10	City of Bardwell	AD	186	N/A	N/A	N/A
11	City of Berea	AD	197	N/A	N/A	N/A
12	City of Corbin	AD	188	N/A	N/A	N/A
13	City of Falmouth	AD	189	N/A	N/A	N/A
14	City of Frankfort	AD	190	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	City of Madisonville	AD	161	N/A	N/A	N/A
2	City of Nicholasville	AD	157	N/A	N/A	N/A
3	City of Paris	AD	83	N/A	N/A	N/A
4	City of Providence	AD	195	N/A	N/A	N/A
5	Appalachian Power Company	RQ	408	N/A	N/A	N/A
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2017/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.
88,488	3,371,056	431,467	2,143,525	5,946,048	1
201,228	6,531,925	983,879	5,026,294	12,542,098	2
8,520	323,840	41,762	209,443	575,045	3
123,743	4,589,156	603,418	2,997,862	8,190,436	4
80,304	3,036,962	391,557	1,948,652	5,377,171	5
18,835	687,793	97,347	459,942	1,245,082	6
691,600	23,354,368	3,372,663	16,712,031	43,439,062	7
296,247	9,739,563	1,452,529	7,275,619	18,467,711	8
198,544	6,525,920	965,029	4,801,300	12,292,249	9
18,813	737,006	90,168	468,594	1,295,768	10
28,669	1,037,382	140,560	701,858	1,879,800	11
4		136		136	12
2,408		96,141		96,141	13
10		654		654	14
1,755,000	59,934,971	8,570,973	42,745,901	111,251,845	
514,059	145,822	13,500,750	-19	13,646,553	
2,269,059	**60,080,793**	**22,071,723**	**42,745,882**	**124,898,398**	

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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.
753		32,304		32,304	1
101		3,523		3,523	2
242					3
-95					4
543		19,731		19,731	5
1,453		49,847		49,847	6
383					7
-141					8
870		32,922		32,922	9
67		1,951		1,951	10
1,210		42,053		42,053	11
421,609		9,761,641		9,761,641	12
28,035		1,090,255		1,090,255	13
		-361		-361	14
1,755,000	59,934,971	8,570,973	42,745,901	111,251,845	
514,059	145,822	13,500,750	-19	13,646,553	
2,269,059	**60,080,793**	**22,071,723**	**42,745,882**	**124,898,398**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
352		10,739		10,739	1
1,203		43,889		43,889	2
41,159		1,625,476		1,625,476	3
30		1,149		1,149	4
10,151		447,408		447,408	5
32		1,273		1,273	6
3,680		136,391		136,391	7
	7,017	5,168	-1	12,184	8
	21,545	11,255	-2	32,798	9
	699	510		1,209	10
	9,442	7,150	-1	16,591	11
	6,408	4,697	-1	11,104	12
	1,476	1,107		2,583	13
	49,319	39,743	-8	89,054	14
1,755,000	59,934,971	8,570,973	42,745,901	111,251,845	
514,059	145,822	13,500,750	-19	13,646,553	
2,269,059	**60,080,793**	**22,071,723**	**42,745,882**	**124,898,398**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
	20,357	17,067	-3	37,421	1
	22,521	11,790	-2	34,309	2
	4,851	3,480	-1	8,330	3
	2,187	1,661		3,848	4
9		594	781	1,375	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
1,755,000	59,934,971	8,570,973	42,745,901	111,251,845	
514,059	145,822	13,500,750	-19	13,646,553	
2,269,059	**60,080,793**	**22,071,723**	**42,745,882**	**124,898,398**	

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 Column: j
Amounts include RQ's related to $6,619 for direct assignment charge and $2,136,906 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 2 Column: j
Amounts include RQ's related to $181,444 for direct assignment charge and $4,844,850 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 3 Column: j
Amounts include RQ's related to $4,094 for direct assignment charge and $205,349 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 4 Column: j
Amounts include RQ's related to $8,614 for direct assignment charge and $2,989,248 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 5 Column: j
Amounts include RQ's related to $10,680 for direct assignment charge and $1,937,972 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 6 Column: j
Amounts include RQ's related to $5,760 for direct assignment charge and $454,182 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 7 Column: j
Amounts include RQ's related to $30,366 for direct assignment charge and $16,681,665 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 8 Column: j
Amounts include RQ's related to $144,190 for direct assignment charge and $7,131,429 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 9 Column: j
Amounts include RQ's related to $8,881 for direct assignment charge and $4,792,419 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 10 Column: j
Amounts include RQ's related to $2,013 for direct assignment charge and $466,581 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 11 Column: j
Amounts include RQ's related to $10,861 for direct assignment charge and $690,997 for wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 12 Column: b
Imbalance

Schedule Page: 310 Line No.: 12 Column: c
(9) KU and LG&E Joint ProForma Open Access Transmission Tariff (OATT) Schedule 4.

Schedule Page: 310 Line No.: 13 Column: b
Market Based Sale

Schedule Page: 310 Line No.: 13 Column: c
(3) KU and LG&E Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)

Schedule Page: 310 Line No.: 14 Column: b
Imbalance

Schedule Page: 310 Line No.: 14 Column: c
(9) KU and LG&E Joint ProForma OATT Schedule 4.

Schedule Page: 310.1 Line No.: 1 Column: b
Market Based Sale

Schedule Page: 310.1 Line No.: 1 Column: c
(3) KU and LG&E Joint MBRT (Short Form Tariff)

Schedule Page: 310.1 Line No.: 2 Column: b
Cost Based Sale

Schedule Page: 310.1 Line No.: 2 Column: c
(5) LG&E Cost Based Rate (CBR) Tariff First Revised Service Agreement No. 3

Schedule Page: 310.1 Line No.: 3 Column: b
Imbalance

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 310.1 Line No.: 3 Column: c
(6) Participation Agreement dated February 9, 2004.
Schedule Page: 310.1 Line No.: 4 Column: b
December 2016 correction made in 2017.
Schedule Page: 310.1 Line No.: 4 Column: c
(6) Participation Agreement dated February 9, 2004.
Schedule Page: 310.1 Line No.: 5 Column: b
Imbalance
Schedule Page: 310.1 Line No.: 5 Column: c
(8) KU and LG&E Joint ProForma OATT Schedule 9.
Schedule Page: 310.1 Line No.: 6 Column: b
Cost Based Sale
Schedule Page: 310.1 Line No.: 6 Column: c
(7) LG&E CBR Tariff Service Agreement No. 4
Schedule Page: 310.1 Line No.: 7 Column: b
Imbalance
Schedule Page: 310.1 Line No.: 7 Column: c
(6) Participation Agreement dated February 9, 2004.
Schedule Page: 310.1 Line No.: 8 Column: b
December 2016 correction made in 2017.
Schedule Page: 310.1 Line No.: 8 Column: c
(6) Participation Agreement dated February 9, 2004.
Schedule Page: 310.1 Line No.: 9 Column: b
Imbalance
Schedule Page: 310.1 Line No.: 9 Column: c
(8) KU and LG&E Joint ProForma OATT Schedule 9.
Schedule Page: 310.1 Line No.: 10 Column: b
Imbalance
Schedule Page: 310.1 Line No.: 10 Column: c
(9) KU and LG&E Joint ProForma OATT Schedule 4.
Schedule Page: 310.1 Line No.: 11 Column: b
Imbalance
Schedule Page: 310.1 Line No.: 11 Column: c
(9) KU and LG&E Joint ProForma OATT Schedule 4.
Schedule Page: 310.1 Line No.: 12 Column: a
KU and LG&E are owned by PPL.
Schedule Page: 310.1 Line No.: 12 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.: 13 Column: b
Market Based Sale
Schedule Page: 310.1 Line No.: 13 Column: c
(3) KU and LG&E Joint MBRT (Short Form Tariff)
Schedule Page: 310.1 Line No.: 14 Column: b
December 2016 correction made in 2017.
Schedule Page: 310.1 Line No.: 14 Column: c
(3) KU and LG&E Joint MBRT (Short Form Tariff)
Schedule Page: 310.2 Line No.: 1 Column: b
Cost Based Sales
Schedule Page: 310.2 Line No.: 1 Column: c
(10) LG&E CBR Tariff
Schedule Page: 310.2 Line No.: 2 Column: b
Imbalance
Schedule Page: 310.2 Line No.: 2 Column: c
(9) KU and LG&E Joint ProForma OATT Schedule 4.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 310.2 Line No.: 3 Column: b
Market Based Sale
Schedule Page: 310.2 Line No.: 3 Column: c
(3) KU and LG&E 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) KU and LG&E 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) KU and LG&E Joint MBRT (Short Form Tariff)
Schedule Page: 310.2 Line No.: 6 Column: b
Cost Based Sale
Schedule Page: 310.2 Line No.: 6 Column: c
(10) LGE CBR Tariff
Schedule Page: 310.2 Line No.: 7 Column: b
Market Based Sale
Schedule Page: 310.2 Line No.: 7 Column: c
(3) KU and LG&E Joint MBRT (Short Form Tariff)
Schedule Page: 310.2 Line No.: 8 Column: b
Annual FERC Municipal Generation formula rate true-up.
Schedule Page: 310.2 Line No.: 9 Column: b
Annual FERC Municipal Generation formula rate true-up.
Schedule Page: 310.2 Line No.: 10 Column: b
Annual FERC Municipal Generation formula rate true-up.
Schedule Page: 310.2 Line No.: 11 Column: b
Annual FERC Municipal Generation formula rate true-up.
Schedule Page: 310.2 Line No.: 12 Column: b
Annual FERC Municipal Generation formula rate true-up.
Schedule Page: 310.2 Line No.: 13 Column: b
Annual FERC Municipal Generation formula rate true-up.
Schedule Page: 310.2 Line No.: 14 Column: b
Annual FERC Municipal Generation formula rate true-up.
Schedule Page: 310.3 Line No.: 1 Column: b
Annual FERC Municipal Generation formula rate true-up.
Schedule Page: 310.3 Line No.: 2 Column: b
Annual FERC Municipal Generation formula rate true-up.
Schedule Page: 310.3 Line No.: 3 Column: b
Annual FERC Municipal Generation formula rate true-up.
Schedule Page: 310.3 Line No.: 4 Column: b
Annual FERC Municipal Generation formula rate true-up.
Schedule Page: 310.3 Line No.: 5 Column: b
Transaction is a Borderline Service Agreement between Old Dominion Power and Appalachian Power Company.
Schedule Page: 310.3 Line No.: 5 Column: c
Appalachian Power Company Rate Schedule FERC No. 408. KU d/b/a Old Dominion Power is making wholesale Borderline Service sales to Appalachian Power Company for purposes of accomodating Appalachian Power Company retail sales to the High Knob residential customers at rates consistent with ODP's Virginia Commission approved retail tariff as may be amended from time to time (consistent with precedent for such borderline agreements as provided for under the rules and order of the Commission).
Schedule Page: 310.3 Line No.: 5 Column: j
Amounts include RQ's related to $540 for direct assignment charge and $241 for wholesale municipal fuel adjustment clause.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	8,486,220	9,288,850
5	(501) Fuel	363,699,361	371,454,709
6	(502) Steam Expenses	21,054,934	21,621,417
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	8,005,105	7,906,668
10	(506) Miscellaneous Steam Power Expenses	31,190,975	31,929,935
11	(507) Rents	12,000	12,000
12	(509) Allowances	3,943	5,176
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	432,452,538	442,218,755
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	8,969,035	9,373,613
16	(511) Maintenance of Structures	8,008,657	8,914,241
17	(512) Maintenance of Boiler Plant	42,741,411	41,554,256
18	(513) Maintenance of Electric Plant	8,628,857	9,690,726
19	(514) Maintenance of Miscellaneous Steam Plant	2,843,366	3,183,676
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	71,191,326	72,716,512
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	503,643,864	514,935,267
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		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	38,820	13,346
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	38,820	13,346
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	122,176	119,814
54	(542) Maintenance of Structures	89,296	185,940
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant	79,361	67,167
57	(545) Maintenance of Miscellaneous Hydraulic Plant	6,351	5,684
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	297,184	378,605
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	336,004	391,951

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Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	1,160,715	1,238,495
63	(547) Fuel	109,007,959	124,138,860
64	(548) Generation Expenses	514,424	480,052
65	(549) Miscellaneous Other Power Generation Expenses	6,378,680	3,847,546
66	(550) Rents	23,014	22,643
67	TOTAL Operation (Enter Total of lines 62 thru 66)	117,084,792	129,727,596
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	526,261	412,308
70	(552) Maintenance of Structures	1,044,187	1,071,996
71	(553) Maintenance of Generating and Electric Plant	3,586,059	3,898,839
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	3,732,298	3,782,100
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	8,888,805	9,165,243
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	125,973,597	138,892,839
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	45,705,642	39,174,611
77	(556) System Control and Load Dispatching	1,908,790	1,928,429
78	(557) Other Expenses	648	27,299
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	47,615,080	41,130,339
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	677,568,545	695,350,396
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,662,214	1,658,242
84			
85	(561.1) Load Dispatch-Reliability	417,453	458,360
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,896,852	1,960,759
87	(561.3) Load Dispatch-Transmission Service and Scheduling	889,753	779,736
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	705,459	839,828
90	(561.6) Transmission Service Studies	46	5,421
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,234,278	1,305,755
94	(563) Overhead Lines Expenses	627,190	606,327
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	3,194,824	3,379,811
97	(566) Miscellaneous Transmission Expenses	13,103,423	12,173,118
98	(567) Rents	146,996	148,901
99	TOTAL Operation (Enter Total of lines 83 thru 98)	23,878,488	23,316,258
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,624,999	1,948,721
108	(571) Maintenance of Overhead Lines	8,797,867	5,959,249
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	296,271	329,741
111	TOTAL Maintenance (Total of lines 101 thru 110)	10,719,137	8,237,711
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	34,597,625	31,553,969

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Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	-159,769	-337,277
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	-159,769	-337,277
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)	-159,769	-337,277
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,641,557	1,561,787
135	(581) Load Dispatching	457,295	461,444
136	(582) Station Expenses	1,964,344	2,014,653
137	(583) Overhead Line Expenses	6,246,106	5,753,589
138	(584) Underground Line Expenses		
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	7,718,805	7,765,196
141	(587) Customer Installations Expenses	-14,998	-57,504
142	(588) Miscellaneous Expenses	6,530,278	5,838,341
143	(589) Rents		7,098
144	TOTAL Operation (Enter Total of lines 134 thru 143)	24,543,387	23,344,604
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	67,018	17,443
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	1,079,285	1,154,455
149	(593) Maintenance of Overhead Lines	29,614,376	31,266,342
150	(594) Maintenance of Underground Lines	377,308	486,391
151	(595) Maintenance of Line Transformers	142,954	97,356
152	(596) Maintenance of Street Lighting and Signal Systems		
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant	338,013	397,957
155	TOTAL Maintenance (Total of lines 146 thru 154)	31,618,954	33,419,944
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	56,162,341	56,764,548
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	3,797,259	3,564,859
160	(902) Meter Reading Expenses	5,120,136	5,391,861
161	(903) Customer Records and Collection Expenses	19,507,799	18,432,371
162	(904) Uncollectible Accounts	4,226,101	4,232,737
163	(905) Miscellaneous Customer Accounts Expenses	2,764	8,511
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	32,654,059	31,630,339

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Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	553,416	536,287
168	(908) Customer Assistance Expenses	19,794,923	20,016,357
169	(909) Informational and Instructional Expenses	494,787	454,823
170	(910) Miscellaneous Customer Service and Informational Expenses	1,249,886	1,501,715
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	22,093,012	22,509,182
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses	791,507	817,344
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	791,507	817,344
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	35,252,106	34,793,230
182	(921) Office Supplies and Expenses	8,310,466	6,748,874
183	(Less) (922) Administrative Expenses Transferred-Credit	5,527,119	5,335,124
184	(923) Outside Services Employed	14,670,293	17,959,527
185	(924) Property Insurance	5,714,993	6,080,606
186	(925) Injuries and Damages	4,623,460	4,123,113
187	(926) Employee Pensions and Benefits	35,113,462	36,633,367
188	(927) Franchise Requirements	4,253	3,961
189	(928) Regulatory Commission Expenses	1,562,407	1,171,527
190	(929) (Less) Duplicate Charges-Cr.	4,253	3,961
191	(930.1) General Advertising Expenses	1,959	19,073
192	(930.2) Miscellaneous General Expenses	5,450,555	4,783,627
193	(931) Rents	2,807,751	2,039,349
194	TOTAL Operation (Enter Total of lines 181 thru 193)	107,980,333	109,017,169
195	Maintenance		
196	(935) Maintenance of General Plant	1,526,833	1,073,893
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	109,507,166	110,091,062
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	933,214,486	948,379,563

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FOOTNOTE DATA

Schedule Page: 320 Line No.: 121 Column: b

The credit balance is the result of the monthly amortization of the net Regulatory Liability for the MISO Exit Fee. During the 2012 KY base rate case, the Company netted the MISO Exit Fee Regulatory Asset and Regulatory Liability together for a net Regulatory Liability as of January 1, 2013.

Schedule Page: 320 Line No.: 121 Column: c

The credit balance is the result of the monthly amortization of the net Regulatory Liability for the MISO Exit Fee. During the 2012 KY base rate case, the Company netted the MISO Exit Fee Regulatory Asset and Regulatory Liability together for a net Regulatory Liability as of January 1, 2013.

Schedule Page: 320 Line No.: 141 Column: b

The credit balance is due to meter tampering charges billed to customers to offset the cost of meter maintenance. The cost is recorded in several accounts.

Schedule Page: 320 Line No.: 141 Column: c

The credit balance is due to meter tampering charges billed to customers to offset the cost of meter maintenance. The cost is recorded in several accounts.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 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	Benham Power Board	OS	(3)	N/A	N/A	N/A
2	Carlisle Armory	OS	(9)	N/A	N/A	N/A
3	Department of Military Affairs	OS	(9)	N/A	N/A	N/A
4	Douglas Langley	OS	(9)	N/A	N/A	N/A
5	East Kentucky Power Cooperative, Inc.	OS	(11)	N/A	N/A	N/A
6	East Kentucky Power Cooperative, Inc.	OS	(3)	N/A	N/A	N/A
7	Fayette County Board of Education	OS	(9)	N/A	N/A	N/A
8	Illinois Municipal Electric Agency	OS	(8)	N/A	N/A	N/A
9	Illinois Municipal Electric Agency	AD	(8)	N/A	N/A	N/A
10	Illinois Municipal Electric Agency	OS	(12)	N/A	N/A	N/A
11	Indiana Municipal Power Agency	OS	(8)	N/A	N/A	N/A
12	Indiana Municipal Power Agency	AD	(8)	N/A	N/A	N/A
13	Indiana Muncipal Power Agency	OS	(12)	N/A	N/A	N/A
14	Kentucky Municipal Energy Agency	OS	(3)	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Municipal Power Agency	OS	(3)	N/A	N/A	N/A
2	Kentucky National Guard	OS	(9)	N/A	N/A	N/A
3	Louisville Gas and Electric Company	SF	(2)	N/A	N/A	N/A
4	Ohio Valley Electric Corporation	OS	(6)	N/A	N/A	N/A
5	Ohio Valley Electric Corporation	AD	(6)	N/A	N/A	N/A
6	Owensboro Municipal Utilities	OS	(3)	N/A	N/A	N/A
7	PJM Interconnection LLC	OS	(1)	N/A	N/A	N/A
8	Rockcastle Hospital Annex	OS	(9)	N/A	N/A	N/A
9	Tennessee Valley Authority	OS	(10)	N/A	N/A	N/A
10	Tennessee Valley Authority	OS	(4)	N/A	N/A	N/A
11	Tennessee Valley Authority	OS	(3)	N/A	N/A	N/A
12	Inadvertent Interchange					
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5				154		154	1
52				1,704		1,704	2
239				5,666		5,666	3
21				733		733	4
7,003				207,095		207,095	5
127				4,353		4,353	6
85				2,792		2,792	7
7							8
12							9
562				12,221		12,221	10
8							11
11							12
784				16,424		16,424	13
46				1,317		1,317	14
1,629,795	438,008		8,734,570	36,971,072		45,705,642	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
923				27,886		27,886	1
114				2,704		2,704	2
1,369,876				30,444,750		30,444,750	3
244,755			8,796,188	6,014,367		14,810,555	4
			-61,618	41,218		-20,400	5
3,170				84,973		84,973	6
509				9,585		9,585	7
55				1,798		1,798	8
700				11,200		11,200	9
713				79,479		79,479	10
18				653		653	11
	438,008						12
							13
							14
1,629,795	438,008		8,734,570	36,971,072		45,705,642	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: b
Imbalance
Schedule Page: 326 Line No.: 1 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4
Schedule Page: 326 Line No.: 2 Column: b
Small Capacity Cogeneration and Small Power Production Qualifying Facility
Schedule Page: 326 Line No.: 2 Column: c
(9) KPSC Standard Rate Rider
Schedule Page: 326 Line No.: 3 Column: b
Large Capacity Cogeneration and Large Power Production Qualifying Facility
Schedule Page: 326 Line No.: 3 Column: c
(9) KPSC Standard Rate Rider
Schedule Page: 326 Line No.: 4 Column: b
Small Capacity Cogeneration and Small Power Production Qualifying Facility
Schedule Page: 326 Line No.: 4 Column: c
(9) KPSC Standard Rate Rider
Schedule Page: 326 Line No.: 5 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 5 Column: c
(11) EEI Master Power Purchase and Sale Agreement dated September 14, 2006.
Schedule Page: 326 Line No.: 6 Column: b
Imbalance
Schedule Page: 326 Line No.: 6 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4
Schedule Page: 326 Line No.: 7 Column: b
Small Capacity Cogeneration and Small Power Production Qualifying Facility
Schedule Page: 326 Line No.: 7 Column: c
(9) KPSC Standard Rate Rider
Schedule Page: 326 Line No.: 8 Column: b
Imbalance
Schedule Page: 326 Line No.: 8 Column: c
(8) Participation Agreement dated February 9, 2004.
Schedule Page: 326 Line No.: 9 Column: b
December 2016 correction made in 2017.
Schedule Page: 326 Line No.: 9 Column: c
(8) Participation Agreement dated February 9, 2004.
Schedule Page: 326 Line No.: 10 Column: b
Imbalance
Schedule Page: 326 Line No.: 10 Column: c
(12) LG&E and KU Joint ProForma OATT Schedule 9.
Schedule Page: 326 Line No.: 11 Column: b
Imbalance
Schedule Page: 326 Line No.: 11 Column: c
(8) Participation Agreement dated February 9, 2004.
Schedule Page: 326 Line No.: 12 Column: b
December 2016 correction made in 2017.
Schedule Page: 326 Line No.: 12 Column: c
(8) Participation Agreement dated February 9, 2004.
Schedule Page: 326 Line No.: 13 Column: b
Imbalance
Schedule Page: 326 Line No.: 13 Column: c
(12) LG&E and KU Joint ProForma OATT Schedule 9.
Schedule Page: 326 Line No.: 14 Column: b
Imbalance

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

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: b
Imbalance

Schedule Page: 326.1 Line No.: 1 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4

Schedule Page: 326.1 Line No.: 2 Column: b
Large Capacity Cogeneration and Large Power Production Qualifying Facility

Schedule Page: 326.1 Line No.: 2 Column: c
(9) KPSC Standard Rate Rider

Schedule Page: 326.1 Line No.: 3 Column: a
KU and LG&E are owned by PPL.

Schedule Page: 326.1 Line No.: 3 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.: 4 Column: a
Intercompany Power Agreement dated September 10, 2010. The Company owns 2.5% of the common stock of OVEC. Purchase of surplus power pursuant to Article 4 of the Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.

Schedule Page: 326.1 Line No.: 4 Column: b
Surplus Power

Schedule Page: 326.1 Line No.: 4 Column: c
(6) Intercompany Power Agreement v 0.0.0 on file with the Commission. Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.

Schedule Page: 326.1 Line No.: 5 Column: a
Intercompany Power Agreement dated September 10, 2010. The Company owns 2.5% of the common stock of OVEC. Purchase of surplus power pursuant to Article 4 of the Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.

Schedule Page: 326.1 Line No.: 5 Column: b
December 2016 true-up of accrual estimate for both energy and demand charges made in 2017.

Schedule Page: 326.1 Line No.: 5 Column: c
(6) Intercompany Power Agreement v 0.0.0 on file with the Commission. Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.

Schedule Page: 326.1 Line No.: 6 Column: b
Imbalance

Schedule Page: 326.1 Line No.: 6 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4

Schedule Page: 326.1 Line No.: 7 Column: b
Market Based Purchase

Schedule Page: 326.1 Line No.: 7 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission

Schedule Page: 326.1 Line No.: 8 Column: b
Small Capacity Cogeneration and Small Power Production Qualifying Facility

Schedule Page: 326.1 Line No.: 8 Column: c
(9) KPSC Standard Rate Rider

Schedule Page: 326.1 Line No.: 9 Column: b
Market Based Purchase

Schedule Page: 326.1 Line No.: 9 Column: c
(10) FERC Electric Rate Schedule No. 28 Interchange Agreement dated July 1, 1977

Schedule Page: 326.1 Line No.: 10 Column: b
Emergency Power

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 326.1 Line No.: 10 Column: c
(4) TEE Contingency Reserve Sharing Agreement dated November 20, 2009.

Schedule Page: 326.1 Line No.: 11 Column: b
Imbalance

Schedule Page: 326.1 Line No.: 11 Column: c
3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Midwest ISO	Various	Various	OS
2	NRG	Various	Various	OS
3	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	FNO
4	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	SFP
5	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	NF
6	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	AD
7	Kentucky Municipal Power Agency	Midwest ISO	Kentucky Municipal Power Agency	FNO
8	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	FNO
9	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	LFP
10	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	SFP
11	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	NF
12	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	FNO
13	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	SFP
14	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	NF
15	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
16	Big Rivers Electric Corporation	Big Rivers Electric Corporation	Big Rivers Electric Corporation	FNO
17	Kentucky Municipal Energy Agency	Midwest ISO	Kentucky Municipal Energy Agency	FNO
18	City of Benham	Midwest ISO	City of Benham	FNO
19	Hoosier Energy	Midwest ISO	Hoosier Energy	FNO
20	Cargill Power Markets, LLC	Various	Various	SFP
21	KU/LG&E	Various	Various	NF
22	KU/LG&E	Various	Various	SFP
23	KU/LG&E	Various	Various	LFP
24	The Energy Authority	Various	Various	NF
25	NextEra Energy	Various	Various	AD
26	Appalachian Power Company	Various	Various	FNO
27	City of Barbourville	Various	City of Barbourville	FNO
28	City of Bardstown	Various	City of Bardstown	FNO
29	City of Bardwell	Various	City of Bardwell	FNO
30	City of Berea	Various	City of Berea	FNO
31	City of Corbin	Various	City of Corbin	FNO
32	City of Falmouth	Various	City of Falmouth	FNO
33	City of Falmouth	Various	City of Falmouth	FNO
34	City of Frankfort	Various	City of Frankfort	FNO
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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 Madisonville	Various	City of Madisonville	FNO
2	City of Nicholasville	Various	City of Nicholasville	FNO
3	City of Paris	Various	City of Paris	FNO
4	City of Providence	Various	City of Providence	FNO
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
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32				
33				
34				
	TOTAL			

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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	Various	Various				1
LGE/KU Joint	Various	Various				2
LGE/KU Joint	East Kentucky Power	East Kentucky Power	253	1,697,570	1,697,570	3
LGE/KU Joint	East Kentucky Power	East Kentucky Power	8	54,593	54,593	4
LGE/KU Joint	East Kentucky Power	East Kentucky Power		7,933	7,933	5
LGE/KU Joint	East Kentucky Power	East Kentucky Power				6
SA 13	Various	LGEE.KMPA	75	446,962	446,962	7
SA 15	Owensboro Municipal	Various	86	188,185	188,185	8
LGE/KU Joint	Owensboro Municipal	Various	173	493,795	493,795	9
LGE/KU Joint	Owensboro Municipal	Various	11			10
LGE/KU Joint	Owensboro Municipal	Various				11
LGE/KU Joint	TVA	TVA	43	232,955	232,955	12
LGE/KU Joint	TVA	TVA		16,058	16,058	13
LGE/KU Joint	TVA	TVA		409	409	14
LGE/KU Joint	TVA	TVA				15
LGE/KU Joint	Big Rivers Electric	Big Rivers Electric	6	41,937	41,937	16
LGE/KU Joint	Various	LGEE.KYMEA	4	23,367	23,367	17
LGE/KU Joint	Midwest ISO	City of Benham		1,544	1,544	18
LGE/KU Joint	Midwest ISO	Hoosier Energy	3	22,903	22,903	19
LGE/KU Joint	Various	Various		8,350	8,350	20
LGE/KU Joint	Various	Various				21
LGE/KU Joint	Various	Various	10			22
LGE/KU Joint	Various	Various	17			23
LGE/KU Joint	Various	Various		587	587	24
LGE/KU Joint	Various	Various				25
408	Various	City of Norton				26
184	Various	City of Barbourville	127			27
185	Various	City of Bardstown	256			28
186	Various	City of Bardwell	11			29
197	Various	City of Berea	175			30
188	Various	City of Corbin	114			31
189	Various	City of Falmouth	25			32
189	Various	City of Falmouth				33
190	Various	City of Frankfort	920			34
			3,010	**3,237,148**	**3,237,148**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	
161	Various	City of Madisonville	374			1
157	Various	City of Nicholasvill	252			2
83	Various	City of Paris	28			3
195	Various	City of Providence	39			4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			3,010	**3,237,148**	**3,237,148**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
		1,037,034	1,037,034	1
		71,683	71,683	2
5,551,743		358,890	5,910,633	3
131,120		11,414	142,534	4
	30,904	1,589	32,493	5
39,327		2,662	41,989	6
1,662,013		335,512	1,997,525	7
1,553,207		351,242	1,904,449	8
3,709,665		244,076	3,953,741	9
267,833		12,235	280,068	10
	147,136	8,988	156,124	11
941,312		60,956	1,002,268	12
	52,190	2,723	54,913	13
	937	69	1,006	14
28,583		1,178	29,761	15
139,580		9,237	148,817	16
115,160		22,041	137,201	17
6,823		1,686	8,509	18
65,625		4,185	69,810	19
	27,163	1,414	28,577	20
	707,577	38,749	746,326	21
31,783		1,659	33,442	22
356,699		23,469	380,168	23
	2,357	126	2,483	24
		-55	-55	25
65			65	26
233,261		9,795	243,056	27
468,868		19,684	488,552	28
21,290		891	22,181	29
320,816		13,494	334,310	30
209,669		8,787	218,456	31
46,529		1,950	48,479	32
		75,899	75,899	33
1,686,030		70,764	1,756,794	34
18,856,535	**968,264**	**2,857,391**	**22,682,190**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
687,452		28,800	716,252	1
462,531		19,431	481,962	2
48,445		2,154	50,599	3
71,106		2,980	74,086	4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
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				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
18,856,535	**968,264**	**2,857,391**	**22,682,190**	

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: m
KU receives ongoing monthly payments from MISO in a Joint Party Settlement Agreement related to uncompensated MISO usage above the 1,000 MW contract right.

Schedule Page: 328 Line No.: 2 Column: m
KU receives ongoing monthly payments from NRG in a Joint Party Settlement Agreement related to uncompensated MISO usage above the 1,000 MW contract right.

Schedule Page: 328 Line No.: 3 Column: m
Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 4 Column: m
Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 5 Column: m
Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 6 Column: k
True-up of prior periods

Schedule Page: 328 Line No.: 6 Column: m
True-up of prior periods

Schedule Page: 328 Line No.: 7 Column: m
Schedule 1, Schedule 2, Schedule 3, Schedule 5, and Schedule 6 charges

Schedule Page: 328 Line No.: 8 Column: m
Schedule 1, Schedule 2, Schedule 3, Schedule 5, and Schedule 6 charges

Schedule Page: 328 Line No.: 9 Column: m
Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 10 Column: m
Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 11 Column: m
Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 12 Column: m
Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 13 Column: m
Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 14 Column: m
Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 15 Column: k
True-up of prior periods

Schedule Page: 328 Line No.: 15 Column: m
True-up of prior periods

Schedule Page: 328 Line No.: 16 Column: m
Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 17 Column: m
Schedule 1, Schedule 2, Schedule 3, Schedule 5, and Schedule 6 charges

Schedule Page: 328 Line No.: 18 Column: m
Schedule 1, Schedule 2, Schedule 3, Schedule 5, and Schedule 6 charges

Schedule Page: 328 Line No.: 19 Column: m
Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 20 Column: m
Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 21 Column: a
KU and LG&E are owned by PPL Corporation

Schedule Page: 328 Line No.: 21 Column: m
Schedule 1 and Schedule 2 charges related to various counterparties

Schedule Page: 328 Line No.: 22 Column: a
KU and LG&E are owned by PPL Corporation

Schedule Page: 328 Line No.: 22 Column: m
Schedule 1 and Schedule 2 charges related to various counterparties

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 23 Column: a

KU and LG&E are owned by PPL Corporation

Schedule Page: 328 Line No.: 23 Column: d

Long-term Firm purchases by KU and LG&E take place under the Open Access Transmission Tariff with intercompany allocations for revenues and expenses determined by the Transmission Coordination Agreement between the Companies. The Tariff is evergreen and the Transmission Coordination Agreement automatically renews unless terminated.

Schedule Page: 328 Line No.: 23 Column: m

Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 24 Column: m

Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 25 Column: m

True-up of prior periods

Schedule Page: 328 Line No.: 27 Column: m

Schedule 1 charges

Schedule Page: 328 Line No.: 28 Column: m

Schedule 1 charges

Schedule Page: 328 Line No.: 29 Column: m

Schedule 1 charges

Schedule Page: 328 Line No.: 30 Column: m

Schedule 1 charges

Schedule Page: 328 Line No.: 31 Column: m

Schedule 1 charges

Schedule Page: 328 Line No.: 32 Column: m

Schedule 1 charges

Schedule Page: 328 Line No.: 33 Column: m

Schedule 1 and Schedule 2 charges

Schedule Page: 328 Line No.: 34 Column: m

Schedule 1 charges

Schedule Page: 328.1 Line No.: 1 Column: m

Schedule 1 charges

Schedule Page: 328.1 Line No.: 2 Column: m

Schedule 1 charges

Schedule Page: 328.1 Line No.: 3 Column: m

Schedule 1 charges

Schedule Page: 328.1 Line No.: 4 Column: m

Schedule 1 charges

Schedule Page: 328.1 Line No.: 4 Column: n

This footnote is not to reference this cell, but the total on Line No.: 35, Column: n.

Reconciliation of revenues from transmission of electricity of others to amount reported in electric operating revenues:

Schedule Page: 330.1, Line No.: 35, Column: n	$ 22,682,190
Elimination of intracompany transmission revenues	(538,500)
Schedule Page: 300, Line No.: 22, Column: b	$ 22,143,690

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) 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.
4. In column (c) 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 (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
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22					
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24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	EKPC	LFP					244,117	244,117
2	KU/LG&E	LFP	189,478	189,478	465,324		31,342	496,666
3	KU/LG&E	SFP	5,867	5,867	19,068		1,005	20,073
4	KU/LG&E	NF	70,249	70,249		279,731	13,257	292,988
5	PJM Interconnect	LFP			2,676,692			2,676,692
6	PJM Interconnect	NF	519	519		361	2,262	2,623
7	PJM Interconnect	AD					165	165
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		266,113	266,113	3,161,084	280,092	292,148	3,733,324

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 332 Line No.: 1 Column: b

The LFP transmission service agreement between East Kentucky Power Cooperative (EKPC) and KU and LG&E has a termination date of 9/1/2019.

Schedule Page: 332 Line No.: 1 Column: g

Schedule 1 and Schedule 2 charges

Schedule Page: 332 Line No.: 2 Column: a

KU and LG&E are owned by PPL.

Schedule Page: 332 Line No.: 2 Column: b

Long-Term Firm purchases by KU and LG&E take place under the Open Access Transmission Tariff (OATT) 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

Schedule 1 and Schedule 2 charges

Schedule Page: 332 Line No.: 3 Column: a

KU and LG&E are owned by PPL.

Schedule Page: 332 Line No.: 3 Column: g

Schedule 1 and Schedule 2 charges

Schedule Page: 332 Line No.: 4 Column: a

KU and LG&E are owned by PPL.

Schedule Page: 332 Line No.: 4 Column: g

Schedule 1 and Schedule 2 charges

Schedule Page: 332 Line No.: 6 Column: g

Schedule 1 and Schedule 2 charges

Schedule Page: 332 Line No.: 7 Column: g

True-up of prior periods of Black Start service charges

Schedule Page: 332 Line No.: 7 Column: h

This footnote is not to reference this cell, but the total on Line No.: 17, Column: h.

Reconciliation of transmission of electricity by others to amount reported in transmission expenses:

Schedule Page: 332, Line No.: 17, Column: h	$ 3,733,324
Elimination of intracompany transmission expenses	(538,500)
Schedule Page: 321, Line No.: 96, Column: b	$ 3,194,824

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,029,466
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	3,705,205
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	PPL Services Corporation:	
7	Stockholder and Debt Service Expenses	505,687
8	Manufactured Gas Plant Remediation Expenses	185,000
9	Direct Employers Association Inc:	
10	Recruiting Expenses	7,500
11	Verizon Wireless:	
12	Cell Phone Expenses	6,899
13	Various Vendors (<$5,000):	
14	Recruiting Expenses	5,352
15	Cell Phone Expenses	4,003
16	Miscellaneous	1,443
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
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31		
32		
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45		
46	TOTAL	5,450,555

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2017/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			15,572,213		15,572,213
2	Steam Production Plant	125,901,683				125,901,683
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	1,218,295				1,218,295
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	36,674,184				36,674,184
7	Transmission Plant	18,580,791				18,580,791
8	Distribution Plant	44,926,214				44,926,214
9	Regional Transmission and Market Operation					
10	General Plant	11,230,168				11,230,168
11	Common Plant-Electric					
12	TOTAL	238,531,335		15,572,213		254,103,548

B. Basis for Amortization Charges

ACCOUNT	RATE	PLANT BALANCE @ 12/31/2017	AMORTIZATION
130200	4%	$ 55,919	$ 6,266
130300	21%	63,093,996	10,561,805
130310	10%	55,494,364	5,004,142

			$ 15,572,213 Column (d)

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Intangible Plant						
13	301 Organization	44					
14	302 Frnchses & Consent	56	20.00		3.63	20-SQ	1.60
15	303 Misc Intgbl Plant	58,409	5.00		20.96	5-SQ	3.10
16	303.10 CCS Software	55,494	25.00		10.06	SQUARE	3.50
17							
18	Steam Production Plant						
19	310 Land	24,171					
20							
21	311 Strctrs & Imprvmts						
22	5603 Tyrone Unit 3	1,631	100.00	-10.00		100-R2.5	
23	5604 Tyrone Units 1&2	583	100.00	-10.00		100-R2.5	
24	5613 Green Rvr Unit 3	2,420	100.00	-10.00		100-R2.5	
25	5614 Green Rvr Unit 4	4,445	100.00	-10.00		100-R2.5	
26	5615 Green Rvr Unt 1&2	1,559	100.00	-10.00		100-R2.5	
27	5621 Brown Unit 1	4,677	100.00	-6.00	0.05	100-R2.5	7.50
28	5622 Brown Unit 2	2,310	100.00	-6.00	0.67	100-R2.5	13.40
29	5623 Brown Unit 3	28,754	100.00	-6.00	1.80	100-R2.5	19.20
30	5630 Brown Unit1-3 FGD	45,383	100.00	-6.00	4.83	100-R2.5	19.40
31	5643 Pineville Unit 3	37	100.00	-10.00		100-R2.5	
32	5650 Ghent Unit 1 FGD	8,397	100.00	-7.00	1.16	100-R2.5	18.30
33	5651 Ghent Unit 1	21,345	100.00	-7.00	0.32	100-R2.5	18.30
34	5652 Ghent Unit 2	16,653	100.00	-7.00	0.88	100-R2.5	18.00
35	5658 Ghent Unit 2 FGD	15,816	100.00	-7.00	1.20	100-R2.5	18.20
36	5653 Ghent Unit 3	51,457	100.00	-7.00	1.47	100-R2.5	21.10
37	5654 Ghent Unit 4	43,271	100.00	-7.00	2.49	100-R2.5	22.10
38	5661 Ghent Unit 4 FGD	37	100.00	-7.00		100-R2.5	
39	5591 System Laboratory	1,117	100.00	-1.00	1.12	100-R2.5	24.10
40	0321 Trmble Cty Unit 2	96,307	100.00	-13.00	2.05	100-R2.5	48.20
41	0322 Trmble Unit 2 FGD	5,556	100.00	-13.00	1.44	100-R2.5	46.80
42							
43	312 Boiler Plant Eqpmt						
44	5603 Tyrone Unit 3	91	65.00	-10.00		65-R2	
45	5603 Tyrone U3 - AP	575	100.00	-10.00		100-S4	
46	5604 Tyrone Units 1&2	36	65.00	-10.00		65-R2	
47	5613 Green Rvr Unit 3	41	65.00	-10.00		65-R2	
48	5613 Gr Rvr Unit 3 -AP	1,832	100.00	-10.00		100-S4	
49	5614 Green Rvr Unit 4	277	65.00	-10.00		65-R2	
50	5615 Green Rvr Unt 1&2	152	65.00	-10.00		65-R2	

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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	5621 Brown Unit 1	34,648	65.00	-6.00	3.16	65-R2	7.40
13	5621 Brown Unit 1 - AP	13,208	100.00	-6.00		100-S4	7.40
14	5622 Brown Unit 2	46,114	65.00	-6.00	2.98	65-R2	13.10
15	5623 Brown Unit 3	442,651	65.00	-6.00	2.65	65-R2	18.90
16	5623 Brown Unit 3 - AP	19,802	100.00	-6.00		100-S4	18.90
17	5630 BrownUnt 1-3 FGD	335,179	65.00	-6.00	4.81	65-R2	19.10
18	5643 Pineville Unit 3	145	65.00	-10.00		65-R2	
19	5643 Pville Unit 3 -AP	91	100.00	-10.00		100-S4	
20	5650 Ghent Unit 1 FGD	139,576	65.00	-7.00	4.17	65-R2	18.10
21	5650 Gh Unit 1 FGD -AP	39	100.00	-7.00		100-R2.5	18.30
22	5651 Ghent Unit 1	355,931	65.00	-7.00	2.93	65-R2	18.00
23	5651 Ghent Unit 1 - AP	2,101	100.00	-7.00		100-S4	18.00
24	5652 Ghent Unit 2	277,189	65.00	-7.00	1.65	65-R2	18.00
25	5658 Ghent Unit 2 FGD	70,126	65.00	-7.00	2.38	65-R2	17.90
26	5658 Gh Unit 2 FGD-AP	1,901	100.00	-7.00		100-S4	17.90
27	5653 Ghent Unit 3	433,488	65.00	-7.00	2.26	65-R2	20.60
28	5660 Ghent Unit 3 FGD	119,328	65.00	-7.00	3.89	65-R2	20.80
29	5654 Ghent Unit 4	751,196	65.00	-7.00	2.60	65-R2	21.70
30	5654 Ghent Unit 4 - AP	32,693	100.00	-7.00		100-S4	21.70
31	5661 Ghent Unit 4 FGD	254,162	65.00	-7.00	4.01	65-R2	21.90
32	0321 Trmble Cty Unit 2	551,960	65.00	-13.00	2.37	65-R2	44.80
33	0321 Trmble Cty U2 -AP	9,104	100.00	-13.00		100-S4	43.30
34	0322 Trmble Unit 2 FGD	72,953	65.00	-13.00	2.22	65-R2	44.40
35							
36	314 Turbogenerator Unt						
37	5613 Green Rvr Unit 3	107	60.00	-10.00		60-R2	4.00
38	5614 Green Rvr Unit 4	57	60.00	-10.00		60-R2	4.00
39	5621 Brown Unit 1	11,381	60.00	-6.00	2.68	60-R2	7.30
40	5622 Brown Unit 2	13,703	60.00	-6.00	1.73	60-R2	13.10
41	5623 Brown Unit 3	45,797	60.00	-6.00	1.73	60-R2	18.80
42	5651 Ghent Unit 1	40,328	60.00	-7.00	2.60	60-R2	17.60
43	5652 Ghent Unit 2	33,057	60.00	-7.00	2.11	60-R2	17.00
44	5653 Ghent Unit 3	43,859	60.00	-7.00	1.97	60-R2	19.60
45	5654 Ghent Unit 4	59,232	60.00	-7.00	2.39	60-R2	20.60
46	0321 Trmble Cty Unit 2	89,986	60.00	-13.00	2.37	60-R2	43.30
47							
48	315 Accessry Elec Eqpm						
49	5603 Tyrone Unit 3	24	70.00	-10.00		70-R3	
50	5613 Green Rvr Unit 3	166	70.00	-10.00		70-R3	4.00

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	5614 Green Rvr Unit 4	480	70.00	-10.00		70-R3	3.90
13	5621 Brown Unit 1	4,321	70.00	-6.00	1.33	70-R3	7.50
14	5622 Brown Unit 2	2,416	70.00	-6.00	2.13	70-R3	13.40
15	5623 Brown Unit 3	15,436	70.00	-6.00	1.34	70-R3	19.30
16	5630 Brown Unt 1-3 FGD	29,324	70.00	-6.00	4.79	70-R3	19.40
17	5650 Ghent Unit 1 FGD	12,223	70.00	-7.00	4.04	70-R3	18.40
18	5651 Ghent Unit 1	12,337	70.00	-7.00	0.60	70-R3	18.20
19	5652 Ghent Unit 2	14,214	70.00	-7.00	1.49	70-R3	17.70
20	5658 Ghent Unit 2 FGD	951	70.00	-7.00	4.94	70-R3	18.40
21	5653 Ghent Unit 3	33,564	70.00	-7.00	1.45	70-R3	20.50
22	5660 Ghent Unit 3 FGD	12,042	70.00	-7.00	3.91	70-R3	21.20
23	5654 Ghent Unit 4	52,185	70.00	-7.00	1.67	70-R3	21.50
24	5661 Ghent Unit 4 FGD	15,148	70.00	-7.00	4.05	70-R3	22.30
25	0321 Trmble Cty Unit 2	45,620	70.00	-13.00	2.18	70-R3	46.60
26	0322 Trmble Unit 2 FGD	1,415	70.00	-13.00	1.66	70-R3	40.90
27							
28	316 Misc Plant Equipmt						
29	5603 Tyrone Unit 3	74	75.00	-10.00		75-R1.5	
30	5604 Tyrone Units 1&2	12	75.00	-10.00		75-R1.5	
31	5613 Green Rvr Unit 3	22	75.00	-10.00		75-R1.5	4.00
32	5614 Green Rvr Unit 4	371	75.00	-10.00		75-R1.5	4.00
33	5615 Green Rvr Unt 1&2	46	75.00	-10.00		75-R1.5	
34	5621 Brown Unit 1	390	75.00	-6.00	1.60	75-R1.5	7.40
35	5622 Brown Unit 2	123	75.00	-6.00	0.06	75-R1.5	13.20
36	5623 Brown Unit 3	6,484	75.00	-6.00	2.35	75-R1.5	18.80
37	5650 Ghent Unit 1 FGD	962	75.00	-7.00	1.27	75-R1.5	17.80
38	5651 Ghent Unit 1	1,846	75.00	-7.00	0.78	75-R1.5	17.80
39	5652 Ghent Unit 2	1,554	75.00	-7.00	0.65	75-R1.5	17.40
40	5653 Ghent Unit 3	4,028	75.00	-7.00	1.20	75-R1.5	20.40
41	5654 Ghent Unit 4	9,999	75.00	-7.00	3.03	75-R1.5	21.40
42	0321 Trmble Cty Unit 2	7,003	75.00	-13.00	2.51	75-R1.5	45.40
43	5591 System Laboratory	3,689	75.00	-1.00	3.04	75-R1.5	23.40
44							
45	317 Asset Rtiremt Oblg	202,002					
46							
47	Hydraulic Prodctn Plnt						
48	330.10 Land Rights	856	100.00			100-R4	
49	331 Structrs & Imprvmt	2,999	90.00	-3.00	2.48	90-S2.5	24.70
50	332 Resrvrs Dams Wtrwy	21,886	105.00	-3.00	2.61	105-S2.5	25.10

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	333 Wtr Whls Trbns Gen	14,047	75.00	-3.00	3.86	75-R3	25.20
13	334 Accessry Elec Eqpt	1,382	40.00	-3.00	3.81	40-L2.5	22.70
14	335 Misc Pwr Plnt Eqpt	329	40.00	-3.00	3.76	40-S0	17.60
15	336 Rds Railrds Bridge	235	60.00	-3.00	3.33	60-R4	21.90
16	337.07 Asset Rtiremt O	646					
17							
18	Other Production Plant						
19	340.10 Land Rights	176	25.00		2.19	SQUARE	178.70
20	340.20 Land	297					
21							
22	341 Strctrs & Imprvmnt						
23	0172 Cane Run Unit 7	47,832	50.00	-12.00	3.03	50-R2.5	35.60
24	5697 Paddys Run Gen 13	2,135	50.00	-6.00	4.16	50-R2.5	14.90
25	5635 Brown CT 5	1,053	50.00	-7.00	3.94	50-R2.5	14.90
26	5636 Brown CT 6	193	50.00	-7.00	4.34	50-R2.5	13.00
27	5637 Brown CT 7	556	50.00	-7.00	4.33	50-R2.5	13.00
28	5638 Brown CT 8	2,013	50.00	-7.00	3.97	50-R2.5	9.20
29	5639 Brown CT 9	4,660	50.00	-7.00	2.76	50-R2.5	14.60
30	5640 Brown CT 10	1,866	50.00	-7.00	2.92	50-R2.5	14.60
31	5641 Brown CT 11	1,919	50.00	-7.00	4.32	50-R2.5	10.20
32	0470 Trimble Cty CT 5	3,740	50.00	-7.00	3.87	50-R2.5	15.80
33	0471 Trimble Cty CT 6	3,589	50.00	-7.00	3.86	50-R2.5	15.80
34	0474 Trimble Cty CT 7	3,559	50.00	-7.00	3.78	50-R2.5	17.70
35	0475 Trimble Cty CT 8	3,549	50.00	-7.00	3.78	50-R2.5	17.70
36	0476 Trimble Cty CT 9	3,656	50.00	-7.00	3.79	50-R2.5	17.70
37	0477 Trimble Cty CT 10	3,653	50.00	-7.00	3.79	50-R2.5	17.70
38	5696 Haeflg Unts 1,2,3	291	50.00	-10.00	19.17	50-R2.5	4.50
39	5468 Brown Solar	1,444	40.00	-5.00	4.24	40-S3	40.00
40							
41	342 Fuel Holders Prdcr						
42	0172 Cane Run Unit 7	6,319	45.00	-12.00	3.10	45-R2.5	35.60
43	0173 Cane Run CT PL	23,411	45.00	-12.00	3.10	45-R2.5	35.60
44	0433 Paddys Run CT PL	6,852	45.00	-6.00	3.10	45-R2.5	14.70
45	5697 Paddys Run Gen 13	1,978	45.00	-6.00	3.89	45-R2.5	14.70
46	5635 Brown CT 5	796	45.00	-7.00	5.00	45-R2.5	14.80
47	5636 Brown CT 6	960	45.00	-7.00	6.96	45-R2.5	13.20
48	5637 Brown CT 7	959	45.00	-7.00	6.99	45-R2.5	13.20
49	5638 Brown CT 8	263	45.00	-7.00	6.53	45-R2.5	9.40
50	5639 Brown CT 9	3,155	45.00	-7.00	4.65	45-R2.5	14.80

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	5640 Brown CT 10	282	45.00	-7.00	5.43	45-R2.5	15.10
13	5641 Brown CT 11	302	45.00	-7.00	7.39	45-R2.5	10.30
14	5645 Brown CT 9 Gas PL	8,347	45.00	-7.00	3.03	45-R2.5	14.20
15	0470 Trimble Cty CT 5	240	45.00	-7.00	3.90	45-R2.5	15.60
16	0471 Trimble Cty CT 6	239	45.00	-7.00	3.90	45-R2.5	15.60
17	0473 Trmbl CT PipL	5,642	50.00	-7.00	3.53	50-R2.5	17.40
18	0474 Trimble Cty CT 7	578	45.00	-7.00	3.82	45-R2.5	17.50
19	0475 Trimble Cty CT 8	576	45.00	-7.00	3.82	45-R2.5	17.50
20	0476 Trimble Cty CT 9	594	45.00	-7.00	3.83	45-R2.5	17.50
21	0477 Trimble Cty CT 10	623	45.00	-7.00	3.85	45-R2.5	17.50
22	5696 Haeflg Unts 1,2,3	472	45.00	-10.00	15.74	45-R2.5	4.40
23							
24	343 Prime Movers						
25	0172 Cane Run Unit 7	255,533	35.00	-12.00	3.57	35-R1.5	30.90
26	5697 Paddys Run Gen 13	19,559	35.00	-6.00	5.53	35-R1.5	13.90
27	5635 Brown CT 5	18,146	35.00	-7.00	4.41	35-R1.5	13.80
28	5636 Brown CT 6	34,686	35.00	-7.00	5.42	35-R1.5	12.20
29	5637 Brown CT 7	32,215	35.00	-7.00	5.28	35-R1.5	12.20
30	5638 Brown CT 8	26,687	35.00	-7.00	5.81	35-R1.5	8.80
31	5639 Brown CT 9	28,845	35.00	-7.00	4.74	35-R1.5	13.60
32	5640 Brown CT 10	25,934	35.00	-7.00	4.94	35-R1.5	13.80
33	5641 Brown CT 11	35,137	35.00	-7.00	4.82	35-R1.5	9.60
34	0470 Trimble Cty CT 5	36,082	35.00	-7.00	4.58	35-R1.5	14.70
35	0471 Trimble Cty CT 6	34,746	35.00	-7.00	4.50	35-R1.5	14.60
36	0474 Trimble Cty CT 7	25,108	35.00	-7.00	4.52	35-R1.5	16.40
37	0475 Trimble Cty CT 8	25,158	35.00	-7.00	4.57	35-R1.5	16.40
38	0476 Trimble Cty CT 9	24,889	35.00	-7.00	4.48	35-R1.5	16.30
39	0477 Trimble Cty CT 10	24,785	35.00	-7.00	4.49	35-R1.5	16.40
40							
41	344 Generators						
42	0172 Cane Run Unit 7	58,191	55.00	-12.00	2.89	55-S2.5	38.20
43	5697 Paddys Run Gen 13	5,455	55.00	-6.00	4.21	55-S2.5	15.30
44	5635 Brown CT 5	2,879	55.00	-7.00	3.98	55-S2.5	15.20
45	5636 Brown CT 6	3,735	55.00	-7.00	4.02	55-S2.5	13.30
46	5637 Brown CT 7	3,741	55.00	-7.00	4.08	55-S2.5	13.30
47	5638 Brown CT 8	5,069	55.00	-7.00	4.04	55-S2.5	9.30
48	5639 Brown CT 9	5,572	55.00	-7.00	2.77	55-S2.5	14.80
49	5640 Brown CT 10	5,058	55.00	-7.00	2.94	55-S2.5	14.90
50	5641 Brown CT 11	5,730	55.00	-7.00	5.55	55-S2.5	10.40

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	0470 Trimble Cty CT 5	4,002	55.00	-7.00	3.85	55-S2.5	16.20
13	0471 Trimble Cty CT 6	3,906	55.00	-7.00	3.85	55-S2.5	16.20
14	0474 Trimble Cty CT 7	3,002	55.00	-7.00	3.75	55-S2.5	18.20
15	0475 Trimble Cty CT 8	2,989	55.00	-7.00	3.75	55-S2.5	18.20
16	0476 Trimble Cty CT 9	3,484	55.00	-7.00	3.76	55-S2.5	18.20
17	0477 Trimble Cty CT 10	3,007	55.00	-7.00	3.76	55-S2.5	18.20
18	5696 Haeflg Unts 1,2,3	2,682	55.00	-10.00	5.37	55-S2.5	4.20
19	5648 Brown Solar	13,069	30.00	-5.00	4.61	30-S1.5	30.00
20							
21	345 Assesry Elec Eqpmt						
22	0172 Cane Run Unit 7	26,172	50.00	-12.00	2.96	50-R3	37.30
23	5697 Paddys Run Gen 13	2,500	50.00	-6.00	4.01	50-R3	15.00
24	5635 Brown CT 5	2,310	50.00	-7.00	4.23	50-R3	15.00
25	5636 Brown CT 6	2,060	50.00	-7.00	4.44	50-R3	13.10
26	5637 Brown CT 7	1,987	50.00	-7.00	4.45	50-R3	13.10
27	5638 Brown CT 8	3,326	50.00	-7.00	5.84	50-R3	9.30
28	5639 Brown CT 9	4,722	50.00	-7.00	3.64	50-R3	14.80
29	5640 Brown CT 10	3,246	50.00	-7.00	3.77	50-R3	14.80
30	5641 Brown CT 11	2,454	50.00	-7.00	4.92	50-R3	10.30
31	0470 Trimble Cty CT 5	1,791	50.00	-7.00	4.18	50-R3	16.10
32	0471 Trimble Cty CT 6	4,577	50.00	-7.00	4.25	50-R3	16.00
33	0474 Trimble Cty CT 7	3,691	50.00	-7.00	4.13	50-R3	18.00
34	1475 Trimble Cty CT 8	3,323	50.00	-7.00	3.79	50-R3	17.90
35	0476 Trimble Cty CT 9	3,247	50.00	-7.00	3.91	50-R3	18.00
36	0477 Trimble Cty CT 10	11,937	50.00	-7.00	4.04	50-R3	17.90
37	5696 Haeflg Unts 1,2,3	816	50.00	-10.00	22.16	50-R3	4.40
38	5648 Brown Solar	445	45.00	-5.00	4.36	45-R2.5	45.00
39							
40	346 Misc Plant Equipmt						
41	0172 Cane Run Unit 7	3,060	40.00	-12.00	3.32	40-R2	33.60
42	5697 Paddys Run Gen 13	1,097	40.00	-6.00	3.93	40-R2	14.20
43	5635 Brown CT 5	2,118	40.00	-7.00	4.01	40-R2	14.20
44	5636 Brown CT 6	101	40.00	-7.00	6.22	40-R2	13.00
45	5637 Brown CT 7	83	40.00	-7.00	6.24	40-R2	13.00
46	5638 Brown CT 8	335	40.00	-7.00	4.98	40-R2	9.00
47	5639 Brown CT 9	842	40.00	-7.00	3.31	40-R2	13.90
48	5640 Brown CT 10	237	40.00	-7.00	3.26	40-R2	13.80
49	5641 Brown CT 11	576	40.00	-7.00	5.22	40-R2	10.00
50	0470 Trimble Cty CT 5	29	40.00	-7.00	4.04	40-R2	15.50

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	0474 Trimble Cty CT 7	9	40.00	-7.00	3.89	40-R2	16.90
13	0475 Trimble Cty CT 8	9	40.00	-7.00	3.89	40-R2	16.90
14	0476 Trimble Cty CT 9	9	40.00	-7.00	3.91	40-R2	16.90
15	0477 Trimble Cty CT 10	42	40.00	-7.00	4.61	40-R2	17.40
16	5696 Haeflg Unts 1,2,3	105	40.00	-10.00	17.75	40-R2	4.30
17	5648 Brown Solar	425	32.00		4.25	32-R2.5	32.00
18							
19	347 Asset Rtiremt Oblg	407					
20							
21	Transmission Plant						
22	350.1 Land Rights	29,530	70.00		0.86	70-R3	48.90
23	350.2 Land	2,360					
24	352.1 Strct Impr Non S	29,418	70.00	-25.00	1.66	70-R3	59.50
25	352.2 Strct Impr Sys C	89	65.00	-25.00	1.66	65-R4	47.90
26	353.1 Station Equipmnt	285,216	60.00	-15.00	1.90	60-R2	46.00
27	353.2 Sys Cntrl Mcrwv	2,624	45.00	-15.00		45-R2	
28	354 Towers & Fixtures	78,033	70.00	-40.00	1.69	70-R4	44.80
29	355 Poles & Fixtures	307,006	58.00	-75.00	2.93	58-R2	48.80
30	356 Ovrhd Cndctr Dvcs	188,111	65.00	-75.00	2.54	65-R3	43.80
31	357 Undrgrnd Conduit	449	50.00		1.70	50-R4	28.70
32	358 Undrgrnd Cndctrs D	1,299	40.00		0.74	40-R3	23.60
33	359 Asset Rtiremt Oblg	557					
34							
35	Distribution Plant						
36	360.1 Land Rights	2,169	70.00		0.64	70-R4	51.40
37	360.2 Land	5,555					
38	361 Strctrs & Imprvmnt	14,412	60.00	-25.00	2.15	60-R2.5	48.40
39	362 Station Equipment	198,035	54.00	-20.00	2.29	54-R2	40.30
40	364 Poles Twrs Fixture	389,092	50.00	-50.00	2.67	50-R1.5	40.10
41	365 Ovrhd Cndctrs Dvc	369,561	47.00	-30.00	2.47	47-R1	38.30
42	366 Undrgrnd Conduit	2,390	50.00		2.32	50-R4	25.60
43	367 Undrgrnd Cndctrs D	194,252	48.00	-20.00	2.43	48-R2	40.20
44	368 Line Transformers	313,647	46.00	-5.00	1.79	46-R2	33.00
45	369 Services	114,368	48.00	-25.00	1.63	48-R1	36.60
46	370 Meters	66,450	28.00		4.29	28-L1	14.70
47	370.01 AMS Meters	1,170	15.00		6.85	15-S2.5	14.50
48	370.20 Meters CT PT	11,208	28.00		3.51	28-L1	4.30
49	371 Instltns Cust Prms	6	28.00	-10.00	0.53	28-O1	19.30
50	373 St Lghtng Sgnl Sys	120,863	28.00	-10.00	4.00	28-L0.5	22.10

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	374 Asset Rtiremt Oblg	670					
13							
14	General Plant						
15	389.2 Land	3,398					
16	390.1 Strctrs Imprvmnt	62,537	50.00	-15.00	2.43	50-S0	39.20
17	390.2 Imprvmt Lesd Prp	473	33.00	-10.00	1.43	33-R1.5	18.00
18	391.1 Ofc Furnitur Eqp	10,580	20.00		4.36	20-SQ	9.90
19	391.2 Non PC Cmptr Eqp	23,100	5.00		11.69	5-SQ	4.00
20	391.31 Prsnl Comptr Eq	4,582	4.00		25.02	4-SQ	2.20
21	392 Trans Eq Cars	1,450	14.00		1.97	14-S2	10.80
22	392.10 Trans Eq Hvy Tr	5,797	16.00		3.19	16-L2.5	13.90
23	393 Stores Equipment	911	25.00		4.40	25-SQ	18.00
24	394 Tool Shop Garage E	13,304	25.00		4.02	25-SQ	17.50
25	396 Pwr Operated Eqp	3,458	16.00		5.65	16-L5	12.00
26	397.00 Comm Eq Microwa	29,997	18.00		4.90	18-L3	13.40
27	397.10 Comm Eq General	19,273	10.00		10.84	10-SQ	5.60
28	397.20 DSM Comm Eq	7,585	10.00		14.08	10-SQ	6.50
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	FERC				
2	Annual Charge	440,220		440,220	
3					
4	State Corporation Commission of Virginia				
5	2017 Rate Case		157,351	157,351	
6	VSCC Case No. PUE 2017-00106				
7					
8	KPSC				
9	2016 Rate Case (Ongoing)		317,297	317,297	2,311,440
10	KPSC Case No. 2016-00370				
11					
12	2014 Rate Case (Jul-15 to Jun-18)		637,661	637,661	956,492
13	KPSC Case No. 2014-00371				
14					
15	Other		9,878	9,878	
16					
17					
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45					
46	TOTAL	440,220	1,122,187	1,562,407	3,267,932

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	440,220					2
							3
							4
Electric	928	157,351					5
							6
							7
							8
			798,029	928	317,297	2,792,172	9
							10
							11
				928	637,661	318,831	12
							13
							14
Electric	928	9,878					15
							16
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							45
		607,449	798,029		954,958	3,111,003	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	A(1)e: Energy Storage	Amortization for Energy Storage Project at Brown
2	A(1)e: CE Power Engineered Services LLC	Energy Storage Project at Brown
3	A(1)e: Other Research Support	Energy Storage Project at Brown: 7 items < $50,000 each plus internal
4		labor and sales tax
5	A(5): Pollution Demonstration Project	Sulfer Analyzer for Future Waste Water Treatment Operations
6	A(6): Research Support Other	Internal Labor and Sales Tax
7	B(1): EPRI	Annual Membership and Annual Research Portfolio
8	B(1): EPRI	Annual Membership and Annual Research Portfolio
9	B(4): Research Support Other	7 items <$50,000 each
10	B(4): University of Kentucky Research Foundn	Amortization of Carbon Capturing Research Regulatory Asset
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
287,949		930	287,949		1
	50,533	188	50,533		2
					3
1,419	282,981	188	284,400	1,286,609	4
	44,809	930	44,809		5
341,853		930	341,853		6
	2,838,929	930	2,838,929		7
	38,975	107	38,975		8
	89,225	930	89,225		9
	102,440	930	102,440		10
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Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 352 Line No.: 4 Column: d

This amount represents reclassification of expenses $282,291 from Louisville Gas & Electric.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	26,045,145		
4	Transmission	4,824,906		
5	Regional Market			
6	Distribution	10,352,863		
7	Customer Accounts	12,318,503		
8	Customer Service and Informational	1,217,890		
9	Sales			
10	Administrative and General	26,033,150		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	80,792,457		
12	Maintenance			
13	Production	17,831,677		
14	Transmission	902,847		
15	Regional Market			
16	Distribution	5,676,325		
17	Administrative and General	643,215		
18	TOTAL Maintenance (Total of lines 13 thru 17)	25,054,064		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	43,876,822		
21	Transmission (Enter Total of lines 4 and 14)	5,727,753		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	16,029,188		
24	Customer Accounts (Transcribe from line 7)	12,318,503		
25	Customer Service and Informational (Transcribe from line 8)	1,217,890		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	26,676,365		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	105,846,521	28,126,619	133,973,140
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	105,846,521	28,126,619	133,973,140
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	25,535,545	22,341,057	47,876,602
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	25,535,545	22,341,057	47,876,602
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,462,312	1,274,110	3,736,422
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,462,312	1,274,110	3,736,422
77	Other Accounts (Specify, provide details in footnote):			
78	Accounts Receivable (work done for others)	1,854,729	317,329	2,172,058
79	MIscellaneous Deferred Debits	272,381	-233,172	39,209
80	Certain Civic, Political and Related Activities and Other	278,567	61,077	339,644
81	Accounts Receivable (Non-jurisdictional - Trimble County)	2,143,440	559,301	2,702,741
82				
83				
84				
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86				
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88				
89				
90				
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92				
93				
94				
95	TOTAL Other Accounts	4,549,117	704,535	5,253,652
96	TOTAL SALARIES AND WAGES	138,393,495	52,446,321	190,839,816

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)				
3	Net Sales (Account 447)	(298,798)	(1,209,839)	(2,072,164)	(2,705,785)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
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46	TOTAL	(298,798)	(1,209,839)	(2,072,164)	(2,705,785)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

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	266,113	MWH	189,045	3,237,148	MWH	914,593
2	Reactive Supply and Voltage	266,113	MWH	102,938	3,237,148	MWH	308,114
3	Regulation and Frequency Response				1,153,853	MWH	128,298
4	Energy Imbalance	4,327,000	MWH	119,336	2,883,000		88,683
5	Operating Reserve - Spinning				1,153,853	MWH	198,862
6	Operating Reserve - Supplement				1,153,853	MWH	198,862
7	Other			165			1,108,662
8	Total (Lines 1 thru 7)	4,859,226		411,484	12,818,855		2,946,074

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 398 Line No.: 7 Column: b
The other services amounts are not associated with a number of units or a unit of measure.

Schedule Page: 398 Line No.: 7 Column: d
The amount consists of Black Start services.

Schedule Page: 398 Line No.: 7 Column: e
The other services amounts are not associated with a number of units or a unit of measure.

Schedule Page: 398 Line No.: 7 Column: g
The amount consists of:

MISO Joint Party Settlement Payments	$ 1,037,034
NRG Joint Party Settlement Payments	71,683
NextEra Energy prior period adjustment	(55)
	$ 1,108,662

Schedule Page: 398 Line No.: 8 Column: b
The number of units per ancillary service type cover multiple schedules and should not be accumulated in total.

Schedule Page: 398 Line No.: 8 Column: e
The number of units per ancillary service type cover multiple schedules and should not be accumulated in total.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,823	6	19	3,873	509	408		33	
2	February	4,519	10	8	3,630	448	408		33	
3	March	4,684	16	7	3,815	461	408			
4	Total for Quarter 1				11,318	1,418	1,224		66	
5	April	3,679	20	16	2,906	365	408			
6	May	4,215	18	15	3,250	437	408		120	
7	June	4,640	13	14	3,710	522	408			
8	Total for Quarter 2				9,866	1,324	1,224		120	
9	July	4,830	21	15	3,866	559	405			
10	August	4,691	17	14	3,774	512	405			
11	September	4,367	21	16	3,458	504	405			
12	Total for Quarter 3				11,098	1,575	1,215			
13	October	3,729	4	16	2,928	396	405			
14	November	4,218	20	8	3,318	427	405		68	
15	December	4,952	28	9	3,961	518	405		68	
16	Total for Quarter 4				10,207	1,341	1,215		136	
17	Total Year to Date/Year				42,489	5,658	4,878		322	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

MONTHLY ISO/RTO 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 Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	18,228,738
3	Steam	16,112,203	23	Requirements Sales for Resale (See instruction 4, page 311.)	1,755,000
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	514,059
5	Hydro-Conventional	59,235	25	Energy Furnished Without Charge	52
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	16,872
7	Other	3,531,444	27	Total Energy Losses	1,255,964
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	21,770,685
9	Net Generation (Enter Total of lines 3 through 8)	19,702,882			
10	Purchases	1,629,795			
11	Power Exchanges:				
12	Received	438,008			
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)	438,008			
15	Transmission For Other (Wheeling)				
16	Received	3,237,148			
17	Delivered	3,237,148			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	21,770,685			

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Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	2,011,270	41,707	4,004	8	900
30	February	1,637,138	2,692	3,630	10	800
31	March	1,798,403	30,277	3,815	16	700
32	April	1,608,924	59,425	2,906	20	1600
33	May	1,715,392	45,582	3,345	18	1500
34	June	1,836,433	44,764	3,710	13	1400
35	July	2,044,219	45,287	3,914	21	1700
36	August	1,932,231	27,374	3,783	17	1500
37	September	1,714,638	72,600	3,518	27	1600
38	October	1,661,226	32,828	3,002	9	1600
39	November	1,778,983	98,749	3,318	20	800
40	December	2,031,828	12,774	3,961	28	900
41	TOTAL	21,770,685	514,059			

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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: EW Brown (b)			Plant Name: Ghent (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	1957			1973		
4	Year Last Unit was Installed	1971			1984		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	757.00			2226.00		
6	Net Peak Demand on Plant - MW (60 minutes)	679			1953		
7	Plant Hours Connected to Load	3590			7802		
8	Net Continuous Plant Capability (Megawatts)	681			1919		
9	When Not Limited by Condenser Water	681			1919		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	136			271		
12	Net Generation, Exclusive of Plant Use - KWh	1416698000			11762287000		
13	Cost of Plant: Land and Land Rights	2304982			20580232		
14	Structures and Improvements	81123818			158094067		
15	Equipment Costs	1020977084			2788946378		
16	Asset Retirement Costs	19408880			107755813		
17	Total Cost	1123814764			3075376490		
18	Cost per KW of Installed Capacity (line 17/5) Including	1484.5638			1381.5708		
19	Production Expenses: Oper, Supv, & Engr	2013385			3989950		
20	Fuel	46120641			257786474		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4945004			13923346		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2171426			5070282		
26	Misc Steam (or Nuclear) Power Expenses	4319551			22179837		
27	Rents	12000			0		
28	Allowances	298			3645		
29	Maintenance Supervision and Engineering	2219435			5848200		
30	Maintenance of Structures	1800017			5718407		
31	Maintenance of Boiler (or reactor) Plant	8192771			27780468		
32	Maintenance of Electric Plant	2481792			5454991		
33	Maintenance of Misc Steam (or Nuclear) Plant	831250			918775		
34	Total Production Expenses	75107570			348674375		
35	Expenses per Net KWh	0.0530			0.0296		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	tons	barrels		tons	barrels	
38	Quantity (Units) of Fuel Burned	722106	9326	0	5449657	24817	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11471	3333	0	11729	3333	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	63.400	73.620	0.000	46.840	68.563	0.000
41	Average Cost of Fuel per Unit Burned	63.395	73.620	0.000	47.220	68.563	0.000
42	Average Cost of Fuel Burned per Million BTU	2.763	12.520	0.000	2.013	11.660	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.032	0.000	0.000	0.022	0.000	0.000
44	Average BTU per KWh Net Generation	11694.000	0.000	0.000	10868.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Haefling* (b)			Plant Name: *Brown CT* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combustion Turbine			Combustion Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Conventional		
3	Year Originally Constructed	1970			1994		
4	Year Last Unit was Installed	1970			2001		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	41.00			781.00		
6	Net Peak Demand on Plant - MW (60 minutes)	25			483		
7	Plant Hours Connected to Load	6			309		
8	Net Continuous Plant Capability (Megawatts)	24			814		
9	When Not Limited by Condenser Water	24			814		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	1			11		
12	Net Generation, Exclusive of Plant Use - KWh	-31000			199202000		
13	Cost of Plant: Land and Land Rights	0			272805		
14	Structures and Improvements	291451			12259366		
15	Equipment Costs	4075508			272897855		
16	Asset Retirement Costs	0			211537		
17	Total Cost	4366959			285641563		
18	Cost per KW of Installed Capacity (line 17/5) Including	106.5112			365.7382		
19	Production Expenses: Oper, Supv, & Engr	0			152636		
20	Fuel	19599			8230848		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	878			100036		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			14880		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			188168		
30	Maintenance of Structures	0			255597		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	80897			1188879		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	101374			10131044		
35	Expenses per Net KWh	-3.2701			0.0509		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil		Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	mcf	barrels		mcf	barrels	
38	Quantity (Units) of Fuel Burned	2366	6	0	2519378	340	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1025	3428	0	1025	3333	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	8.068	84.957	0.000	3.254	97.081	0.000
41	Average Cost of Fuel per Unit Burned	8.068	84.957	0.000	3.254	97.081	0.000
42	Average Cost of Fuel Burned per Million BTU	7.872	14.050	0.000	3.175	16.510	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.041	0.258	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	12972.000	15625.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			0.00			0.00
6	Net Peak Demand on Plant - MW (60 minutes)			0			0
7	Plant Hours Connected to Load			0			0
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			0			0
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			0			0
13	Cost of Plant: Land and Land Rights			0			0
14	Structures and Improvements			0			0
15	Equipment Costs			0			0
16	Asset Retirement Costs			0			0
17	Total Cost			0			0
18	Cost per KW of Installed Capacity (line 17/5) Including			0			0
19	Production Expenses: Oper, Supv, & Engr			0			0
20	Fuel			0			0
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			0			0
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			0
26	Misc Steam (or Nuclear) Power Expenses			0			0
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			0
30	Maintenance of Structures			0			0
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			0			0
33	Maintenance of Misc Steam (or Nuclear) Plant			0			0
34	Total Production Expenses			0			0
35	Expenses per Net KWh			0.0000			0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: Trimble County (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Steam			1
Conventional			2
2011			3
2011			4
509.00	0.00	0.00	5
464	0	0	6
5532	0	0	7
445	0	0	8
445	0	0	9
0	0	0	10
92	0	0	11
2933218000	0	0	12
1154662	0	0	13
101863720	0	0	14
780347938	0	0	15
21307179	0	0	16
904673499	0	0	17
1777.3546	0	0	18
1666790	0	0	19
59736597	0	0	20
0	0	0	21
2102938	0	0	22
0	0	0	23
0	0	0	24
707426	0	0	25
4540853	0	0	26
0	0	0	27
1	0	0	28
749384	0	0	29
340361	0	0	30
6633035	0	0	31
677668	0	0	32
661852	0	0	33
77816905	0	0	34
0.0265	0.0000	0.0000	35

									Line No.
Coal	Oil								36
tons	barrels								37
1685346	2723	0	0	0	0	0	0	0	38
10738	3333	0	0	0	0	0	0	0	39
45.330	51.689	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
34.545	51.689	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
1.609	8.791	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.020	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
12340.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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: *Paddy's Run 13 CT* (d)			Plant Name: *Trimble County CT* (e)			Plant Name: *Cane Run NGCC* (f)			Line No.
Combustion Turbine			Combustion Turbine			Steam			1
Conventional			Conventional			Conventional			2
2001			2002			2015			3
2001			2004			2015			4
84.00			784.00			630.00			5
75			490			542			6
263			686			4795			7
69			626			516			8
69			626			516			9
0			0			0			10
3			5			35			11
29866000			508930000			2782834000			12
6286			26174			6243			13
2134877			21745929			47831976			14
37624354			228481301			382810332			15
34623			95117			65714			16
39800140			250348521			430714265			17
473.8112			319.3221			683.6734			18
0			0			1008079			19
2367806			32755020			65634686			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
60619			442381			3006524			25
0			0			0			26
8134			0			0			27
0			0			0			28
16008			0			322086			29
1042			0			787548			30
0			0			0			31
239252			882714			4804638			32
0			0			0			33
2692861			34080115			75563561			34
0.0902			0.0670			0.0272			35
Gas			Gas			Gas			36
mcf			mcf			mcf			37
320055	0	0	5615384	0	0	18500797	0	0	38
1030	0	0	1033	0	0	1026	0	0	39
7.398	0.000	0.000	5.833	0.000	0.000	3.548	0.000	0.000	40
7.398	0.000	0.000	5.833	0.000	0.000	3.548	0.000	0.000	41
7.180	0.000	0.000	5.648	0.000	0.000	3.457	0.000	0.000	42
0.079	0.000	0.000	0.064	0.000	0.000	0.024	0.000	0.000	43
11042.000	0.000	0.000	11395.000	0.000	0.000	6823.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
		0.00			0.00			0.00	5
		0			0			0	6
		0			0			0	7
		0			0			0	8
		0			0			0	9
		0			0			0	10
		0			0			0	11
		0			0			0	12
		0			0			0	13
		0			0			0	14
		0			0			0	15
		0			0			0	16
		0			0			0	17
		0			0			0	18
		0			0			0	19
		0			0			0	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		0			0			0	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		0			0			0	30
		0			0			0	31
		0			0			0	32
		0			0			0	33
		0			0			0	34
		0.0000			0.0000			0.0000	35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
		0.00			0.00			0.00	5
		0			0			0	6
		0			0			0	7
		0			0			0	8
		0			0			0	9
		0			0			0	10
		0			0			0	11
		0			0			0	12
		0			0			0	13
		0			0			0	14
		0			0			0	15
		0			0			0	16
		0			0			0	17
		0			0			0	18
		0			0			0	19
		0			0			0	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		0			0			0	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		0			0			0	30
		0			0			0	31
		0			0			0	32
		0			0			0	33
		0			0			0	34
		0.0000			0.0000			0.0000	35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 403 Line No.: -1 Column: d

Partnership Expenses included in Column d:

Line No.: 19	Production Expenses: Oper, Supv & Engr	$	(555,597)
Line No.: 20	Fuel		(19,075,148)
Line No.: 22	Steam Expenses		(691,216)
Line No.: 25	Electric Expenses		(235,809)
Line No.: 26	Misc Steam Power Expenses		(1,513,620)
Line No.: 29	Maintenance Supervision and Engineering		(234,633)
Line No.: 30	Maintenance of Structures		(113,454)
Line No.: 31	Maintenance of Boiler Plant		(2,161,630)
Line No.: 32	Maintenance of Electric Plant		(226,535)
Line No.: 33	Maintenance of Misc Steam Plant		(220,618)
Line No.: 34	Total Production Expenses	$	(25,028,260)

Total Power Production Expenses per Schedule Page: 402-403, Sum of Line No.: 34, Column: b-f	$	652,478,693
Operation and Maintenance Expenses on Retired Plants		2,045,053
Maintenance Expenses on Solar Plant per Schedule Page: 410-411, Line No.: 1, Column: j		121,976
IMEA-IMPA Partnership Expenses		(25,028,260)
Rounding		(1)
Total Power Production Expenses per Schedule Page: 320-321, Sum of Line No.: 21 & 74, Column: b	$	629,617,461

Schedule Page: 403 Line No.: 1 Column: d

KU owns 60.75% of Trimble County Steam Unit 2, a 838 MW unit, with the remaining percentage owned by LG&E, IMEA and IMPA. The information presented in here represents KU's share.

Schedule Page: 402.1 Line No.: -1 Column: b

Haefling turbines are peak load service units.

Schedule Page: 402.1 Line No.: -1 Column: c

KU owns 47% of Brown CT Unit 5, a 123 MW unit, and 62% of Units 6 and 7, 177 MW each. The remaining percentages of Units 5, 6 and 7 are owned by LG&E. KU also owns 100% of Brown CT Units 8, 9, 10, and 11. Brown CT units 5, 6, 7, 8, 9, 10 and 11 are peak load service units. The information presented in here represents KU's share.

Schedule Page: 403.1 Line No.: -1 Column: d

KU owns 47% of Paddy's Run Unit 13, a 178 MW unit, with the remaining percentage owned by LG&E. Paddy's Run Unit 13 is a peak load service unit. The information presented in here represnts KU's share.

Schedule Page: 403.1 Line No.: -1 Column: e

KU owns 71% of Trimble County CT Units 5 and 6 and 63% of Units 7, 8, 9 and 10. The remaining percentages for Units 5, 6, 7, 8, 9 and 10 are owned by LG&E. The total Nameplate Ratings for these units are 199 MW per unit and they are peak load service units. The information presented in here represents KU's share.

Schedule Page: 403.1 Line No.: -1 Column: f

KU owns 78% of Cane Run NGCC, a 808 MW unit, with the remaining percentage owned by LG&E. The information presented in here represents KU's share.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Dix Dam (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1923	
4	Year Last Unit was Installed	1924	
5	Total installed cap (Gen name plate Rating in MW)	34.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	32	0
7	Plant Hours Connect to Load	2,489	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	32	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	3	0
12	Net Generation, Exclusive of Plant Use - Kwh	59,235,000	0
13	Cost of Plant		
14	Land and Land Rights	855,637	0
15	Structures and Improvements	2,999,390	0
16	Reservoirs, Dams, and Waterways	21,885,646	0
17	Equipment Costs	15,757,987	0
18	Roads, Railroads, and Bridges	234,509	0
19	Asset Retirement Costs	645,788	0
20	TOTAL cost (Total of 14 thru 19)	42,378,957	0
21	Cost per KW of Installed Capacity (line 20 / 5)	1,246.4399	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	38,820	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	122,176	0
30	Maintenance of Structures	89,296	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	79,361	0
33	Maintenance of Misc Hydraulic Plant	6,351	0
34	Total Production Expenses (total 23 thru 33)	336,004	0
35	Expenses per net KWh	0.0057	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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
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0	0	0	9
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0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
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."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
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			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Brown Solar	2016	6.10	6.0	10,643,000	15,544,788
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45						
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Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
2,548,326			121,976			1
						2
						3
						4
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						7
						8
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						45
						46

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 410 Line No.: 1 Column: c

The Name Rating for Brown Photovoltaic Solar Unit represents 61% ownership of the 10 MW unit. The remaining percentage of the unit is owned by LG&E.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	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	Pocket	Pineville	500.00	500.00	ST	35.48		
2	Pocket	Phipps Bend	500.00	500.00	ST	21.39		
3	Ghent Plant	Brown North	345.00	345.00	ST	113.87		
4	Ghent Plant	Batesville	345.00	345.00	ST	7.80		
5	Brown Plant	Elmer Smith	345.00	345.00	HF,SP,ST	171.06		
6	Brown North	K.U. Park	345.00	345.00	ST	102.47		2
7	Green River	AEC Buss	161.00	161.00	HF,ST,WP	183.09		
8	Green River	Morganfield	161.00	161.00	HF,WP	55.38		
9	Elihu	Dorchester	161.00	161.00	HF,ST	86.06		
10	Lake Reba	Dorchester	161.00	161.00	HF,ST	99.15		1
11	Pineville	Harlan	161.00	161.00	HF,WP	48.34		
12	Pineville 149	Pineville 192	161.00	161.00	HF	0.12		1
13	East Ky. Power Cooperative	Taylor County	161.00	161.00	SP	3.97		1
14	Imboden	Harlan	161.00	161.00	HF,SP,WP,ST	43.82		
15	Ghent Plant	Brown Plant	138.00	138.00	ST	90.47		
16	Brown Plant	Green River	138.00	138.00	HF,SP,WP,ST	169.43		
17	Kenton	Rodburn	138.00	138.00	HF	45.74		1
18	Green River	Brown North	138.00	138.00	HF,SP,ST	166.68		
19	Fawkes	Rodburn	138.00	138.00	HF,ST,WP	64.52		1
20	Clifty Creek	Carrollton	138.00	138.00	HF,SP,ST,WP	144.71		
21	Brown Plant	Lake Reba	138.00	138.00	HF,SP	29.44		1
22	Brown Plant	Haefling	138.00	138.00	HF,SP,ST,WP	29.32		
23	Ghent Plant	Kenton Station	138.00	138.00	HF,WF	72.78		1
24	Ghent Plant	Adams	138.00	138.00	HF,SP,ST	56.77		
25	Hardin County	Rogersville	138.00	138.00	HF	10.24		1
26	Virginia City	Clinch River (AEP Int. Pt)	138.00	138.00	HF	7.89		1
27	69KV Lines		69.00	69.00	Various	2,206.42		
28								
29								
30								
31								
32								
33								
34								
35	Exp Applicable to All Lines							
36					TOTAL	4,066.41		11

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
954 mcm	3,117,591	15,708,717	18,826,308					1
954 mcm	280,371	7,950,059	8,230,430					2
795 mcm	2,495,681	17,212,033	19,707,714					3
954 mcm	437,159	6,217,395	6,654,554					4
954 mcm	5,490,631	68,106,470	73,597,101					5
954 mcm	1,111,580	26,077,449	27,189,029					6
556 mcm	1,284,447	25,133,682	26,418,129					7
556 mcm	268,660	4,628,066	4,896,726					8
556 mcm	270,147	10,353,147	10,623,294					9
556 mcm	559,988	7,794,483	8,354,471					10
795 mcm	300,849	6,888,249	7,189,098					11
954 mcm		205,543	205,543					12
556 mcm	261,988	307,188	569,176					13
795 mcm	84,143	6,459,169	6,543,312					14
954 mcm	419,701	6,488,099	6,907,800					15
556 mcm	450,190	15,534,472	15,984,662					16
397 mcm	98,119	4,678,267	4,776,386					17
795 mcm	736,912	21,558,222	22,295,134					18
556 mcm	579,168	5,540,642	6,119,810					19
795 mcm	891,092	28,646,868	29,537,960					20
556 mcm	80,240	3,118,420	3,198,660					21
795 mcm	191,989	5,459,900	5,651,889					22
795 mcm	446,861	7,492,227	7,939,088					23
795 mcm	245,501	15,536,148	15,781,649					24
795 mcm	245,092	1,085,037	1,330,129					25
795 mcm	344,980	4,788,455	5,133,435					26
Various	8,799,216	251,755,704	260,554,920					27
								28
								29
								30
								31
								32
								33
								34
				627,190	8,797,867	146,996	9,572,053	35
	29,492,296	574,724,111	604,216,407	627,190	8,797,867	146,996	9,572,053	36

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 1 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 2 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 3 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 4 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 5 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 7 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 8 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 9 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 11 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 14 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 15 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 16 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 18 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 20 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 22 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 24 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 27 Column: h
Contains both single and double circuitry.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
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43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	A. O. Smith - Mt. Sterling	Transmission*	69.00		
2	Adams - Georgetown	Transmission*	138.00	69.00	13.20
3	Alcade - Somerset	Transmission*	345.00	161.00	13.20
4	American Ave. - Lexington	Transmission*	138.00	69.00	13.20
5	Arnold - Cumberland	Transmission*	161.00	69.00	13.20
6	Artemus - Pineville	Transmission*	161.00	69.00	13.20
7	Avon - Fayette	Transmission*	69.00		
8	Bardstown - Campbellsville	Transmission*	138.00	69.00	13.20
9	Bardstown City - Campbellsville	Transmission*	69.00		
10	Barlow	Transmission*	69.00		
11	Beattyville - Richmond	Transmission*	161.00	69.00	13.20
12	Bimble	Transmission*	69.00		
13	Blackwell	Transmission*	138.00		
14	Bluegrass Ordinance	Transmission*	69.00		
15	Bond - Coeburn	Transmission*	69.00		
16	Bonds Mill	Transmission*	69.00		
17	Bonnieville - Horse Cave	Transmission*	138.00	69.00	13.20
18	Boone Ave. - Winchester	Transmission*	69.00		
19	Boonesboro North - Winchester	Transmission*	138.00	69.00	13.20
20	Boyle County	Transmission*	69.00		
21	Broadhead Switching	Transmission*	69.00		
22	Bromley	Transmission*	69.00		
23	Brown CT - Harrodsburg	Transmission*	138.00		
24	Brown North - Harrodsburg	Transmission*	345.00	138.00	13.20
25	Brown Plant - Harrodsburg	Transmission*	138.00		
26	Carntown - Augusta	Transmission*	138.00	69.00	13.20
27	Carrollton - Carrollton	Transmission*	138.00	69.00	13.20
28	Cary Switching	Transmission*	69.00		
29	Clark County - Winchester	Transmission*	138.00	69.00	13.20
30	Clinton	Transmission*	69.00		
31	Coleman Road - McCracken Co.	Transmission*	161.00		
32	Corydon - Henderson	Transmission*	161.00	69.00	13.20
33	Crittendon County - Marion	Transmission*	161.00	69.00	13.20
34	Cynthiana Switching	Transmission*	69.00		
35	Danville North - Danville	Transmission*	138.00	69.00	13.20
36	Daviess County	Transmission*	345.00		
37	Delvinta	Transmission*	161.00		
38	Dix Dam - Mercer	Transmission*	69.00		
39	Dow Corning West	Transmission*	138.00		
40	Dorchester - Norton	Transmission*	161.00	69.00	13.20

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Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Earlington North - Earlington	Transmission*	161.00	69.00	13.20
2	East Frankfort - Frankfort	Transmission*	138.00	69.00	13.20
3	Elihu - Somerset	Transmission*	161.00	69.00	13.20
4	Elizabethtown - Elizabethtown	Transmission*	138.00	69.00	13.20
5	Eminence	Transmission*	69.00		
6	Evarts	Transmission*	69.00		
7	Farley - Corbin	Transmission*	161.00	69.00	13.20
8	Farmers - Morehead	Transmission*	138.00	69.00	13.20
9	Fawkes - Richmond	Transmission*	138.00	69.00	13.20
10	Finchville	Transmission*	69.00		
11	FMC - Lexington	Transmission*	69.00		
12	Ghent Plant - Carrollton	Transmission*	345.00	138.00	
13	Ghent Plant - Carrollton	Transmission*	345.00	138.00	25.00
14	Goddard	Transmission*	138.00		
15	Gorge Switching	Transmission*	69.00		
16	Grahamville - Barlow	Transmission*	161.00	69.00	13.20
17	Green River Plant - Greenville	Transmission*	138.00	69.00	13.20
18	Green River Plant - Greenville	Transmission*	161.00	138.00	13.20
19	Green River Steel - Greenville	Transmission*	138.00	69.00	13.80
20	Haefling - Lexington	Transmission*	138.00	69.00	13.20
21	Hardin County - Elizabethtown	Transmission*	345.00	138.00	13.20
22	Hardin County - Elizabethtown	Transmission*	138.00	69.00	13.20
23	Hardinsburg - Hardinsburg	Transmission*	138.00		
24	Harrodsburg	Transmission*	69.00		
25	Harlan "Y" - Harlan	Transmission*	161.00	69.00	13.20
26	Higby Mill - Lexington	Transmission*	138.00	69.00	13.20
27	Hillside	Transmission*	69.00		
28	Howards Branch	Transmission*	161.00		
29	Hughes Lane - Lexington	Transmission*	69.00		
30	Imboden - Big Stone Gap	Transmission*	161.00	69.00	13.20
31	Indian Hill	Transmission*	69.00		
32	Kenton - Maysville	Transmission*	138.00	69.00	13.20
33	KU Park - Pineville	Transmission*	69.00		
34	LaGrange East	Transmission*	69.00		
35	Lake Reba - Richmond	Transmission*	138.00	69.00	13.20
36	Lake Reba Tap - Richmond	Transmission*	161.00	138.00	6.60
37	Lancaster Switching	Transmission*	69.00		
38	Lansdowne - Lexington	Transmission*	138.00	69.00	13.20
39	Lebanon - Lebanon	Transmission*	80.00	40.00	13.20
40	Lebanon City	Transmission*	69.00		

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Leitchfield - Leitchfield	Transmission*	138.00	69.00	13.20
2	Leitchfield East	Transmission*	69.00		
3	Lexington Plant - Lexington	Transmission*	69.00		
4	Livingston County	Transmission*	161.00		
5	London - London	Transmission*	69.00		
6	Loudon Ave - Lexington	Transmission*	138.00	69.00	13.20
7	Lynch - Harlan	Transmission*	69.00		
8	Manchester	Transmission*	69.00		
9	Marion	Transmission*	69.00		
10	Matanzas	Transmission*	161.00	138.00	13.20
11	Meldrum Switching	Transmission*	69.00		
12	Meredith	Transmission*	138.00		
13	Middlesboro - Middlesboro	Transmission*	69.00		
14	Millersburg - Millersburg	Transmission*	69.00		
15	Morganfield - Morganfield	Transmission*	161.00	69.00	13.20
16	Mt. Vernon - Mt. Vernon	Transmission*	69.00		
17	N.A.S.	Transmission*	345.00	138.00	
18	Nebo - Nebo	Transmission*	69.00		
19	Newtown	Transmission*	69.00		
20	Nicholasville	Transmission*	69.00		
21	North London - London	Transmission*	69.00		
22	North Princeton - Princeton	Transmission*	161.00		
23	Ohio County - Beaver Dam	Transmission*	138.00	69.00	13.20
24	Paducah Primary - Paducah	Transmission*	161.00		
25	Paris	Transmission*	138.00	69.00	13.20
26	Pineville - Pineville	Transmission*	345.00	161.00	13.20
27	Pineville - Pineville	Transmission*	500.00	345.00	34.50
28	Pineville - Pineville	Transmission*	161.00	69.00	13.20
29	Pineville Switching - Pineville	Transmission*	161.00		
30	Pisgah - Lexington	Transmission*	138.00	69.00	13.20
31	Pittsburg - London	Transmission*	161.00	69.00	13.20
32	Pocket - Pennington Gap	Transmission*	161.00	69.00	13.20
33	Pocket North - Pennington Gap	Transmission*	500.00	161.00	
34	Princeton - Princeton	Transmission*	69.00		
35	Richmond - Richmond	Transmission*	69.00		
36	River Queen - Muhlenberg	Transmission*	161.00	69.00	13.20
37	Rocky Branch	Transmission*	69.00		
38	Rodburn - Morehead	Transmission*	138.00	69.00	13.20
39	Rogersville - Radcliff	Transmission*	138.00	69.00	13.20
40	Scott County	Transmission*	138.00	69.00	13.20

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Shelbyville - Shelbyville	Transmission*	69.00		
2	Shrewsbury Switching	Transmission*	138.00		
3	Simmons	Transmission*	69.00		
4	Somerset North - Somerset	Transmission*	69.00		
5	South Paducah	Transmission*	161.00	69.00	13.20
6	Spears Switching	Transmission*	69.00		
7	Spencer Road - Mt. Sterling	Transmission*	138.00	69.00	13.20
8	St. Paul	Transmission*	69.00		
9	Stanford North	Transmission*	69.00		
10	Sweet Hollow	Transmission*	69.00		
11	Taylor County - Campbellsville	Transmission*	161.00	69.00	13.20
12	Tyrone - Versailles	Transmission*	138.00	69.00	13.20
13	UK Medical Center - Lexington	Transmission*	69.00		
14	Uniontown	Transmission*	69.00		
15	Versailles Bypass - Versailles	Transmission*	69.00		
16	Virginia City - Norton	Transmission*	138.00	69.00	13.20
17	Walker - Earlington	Transmission*	161.00	69.00	13.20
18	West Cliff - Harrodsburg	Transmission*	138.00	69.00	13.20
19	West Frankfort - Shelbyville	Transmission*	345.00	138.00	13.20
20	West Frankfort - Shelbyville	Transmission*	138.00	69.00	13.20
21	West Garrard - Lancaster	Transmission*	345.00		
22	West Irvine - Irvine	Transmission*	161.00	69.00	13.20
23	West Lexington - Lexington	Transmission*	345.00	138.00	13.20
24	Wheatcroft	Transmission*	69.00		
25	Wickliffe - Barlow	Transmission*	161.00	69.00	13.20
26	Williamsburg Switching	Transmission*	69.00		
27	Winchester	Transmission*	69.00		
28	Wofford	Transmission*	69.00		
29	Total Transmission		19963.00	6112.00	924.70
30					
31	A.O. Smith - Mt. Sterling	Distribution*	69.00	12.47	
32	Adams	Distribution*	69.00	34.50	
33	Adams	Distribution*	69.00	12.47	
34	Airgas	Distribution*	138.00	13.80	
35	Aisin	Distribution*	69.00	12.47	
36	Alexander - Versailles	Distribution*	69.00	12.47	
37	American Ave. - Lexington	Distribution*	69.00	12.47	
38	Andover - Norton	Distribution*	69.00	34.50	
39	Appalachia	Distribution*	69.00	12.47	
40	Ashland Ave. - Lexington	Distribution*	69.00	4.16	

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Ashland Pipe - Lexington	Distribution*	69.00	12.47	
2	Atoka	Distribution*	69.00	12.47	
3	Augusta 12KV	Distribution*	69.00	12.47	
4	Bardstown City	Distribution*	69.00	12.47	
5	Bardstown Industrial	Distribution*	69.00	12.47	
6	Barlow	Distribution*	69.00	12.47	
7	Beaver Dam - Beaver Dam	Distribution*	69.00	12.47	
8	Beaver Dam North - Beaver Dam	Distribution*	69.00	12.47	
9	Belt Line - Lexington	Distribution*	69.00	12.47	
10	Bevier - Earlington	Distribution*	69.00	34.50	
11	Big Stone Gap - Big Stone Gap	Distribution*	69.00	12.47	
12	Black Branch Road	Distribution*	138.00	12.47	
13	Bond - Coeburn	Distribution*	69.00	12.47	
14	Bond - Coeburn	Distribution*	69.00	23.00	
15	Boone Ave. - Winchester	Distribution*	69.00	12.47	
16	Boonesboro Park	Distribution*	69.00	12.47	
17	Borg Warner - Earlington	Distribution*	69.00	12.47	
18	Bryant Road - Lexington	Distribution*	69.00	12.47	
19	Buchanan - Lexington	Distribution*	69.00	4.16	
20	Buena Vista	Distribution*	69.00	12.47	
21	Burnside - Somerset	Distribution*	69.00	12.47	
22	Calloway	Distribution*	69.00	12.47	
23	Camargo - Mt. Sterling	Distribution*	69.00	12.47	
24	Camp Breckinridge	Distribution*	69.00	12.47	
25	Campbellsville 1 - Campbellsville	Distribution*	69.00	12.47	
26	Campbellsville Industrial - Campbellsville	Distribution*	69.00	12.47	
27	Carlisle	Distribution*	69.00	12.47	
28	Carntown - Augusta	Distribution*	69.00	12.47	
29	Caron - London	Distribution*	69.00	12.47	
30	Carrollton - Carrollton	Distribution*	69.00	12.47	
31	Catrons Creek	Distribution*	69.00	12.47	
32	Cawood - Harlan	Distribution*	69.00	12.47	
33	Central City	Distribution*	69.00	12.47	
34	Central City South	Distribution*	69.00	12.47	
35	Clays Mill - Lexington	Distribution*	138.00	12.47	
36	Clinch Valley - Norton	Distribution*	69.00	12.47	
37	Clinton	Distribution*	69.00	12.47	
38	Columbia - Columbia	Distribution*	69.00	12.47	
39	Columbia South - Columbia	Distribution*	69.00	12.47	
40	Corbin East - Corbin	Distribution*	69.00	12.47	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Corbin US Steel	Distribution*	69.00	12.47	
2	Corning 12KV	Distribution*	69.00	12.47	
3	Corning Harrodsburg	Distribution*	69.00	12.47	
4	Corporate Drive	Distribution*	69.00	12.47	
5	Cynthiana	Distribution*	69.00	12.47	
6	Cynthiana South	Distribution*	69.00	12.47	
7	Danville Central - Danville	Distribution*	69.00	12.47	
8	Danville East - Danville	Distribution*	69.00	12.47	
9	Danville Industrial - Danville	Distribution*	69.00	12.47	
10	Danville North - Danville	Distribution*	69.00	12.47	
11	Danville West - Danville	Distribution*	69.00	12.47	
12	Dark Hollow - Richmond	Distribution*	69.00	12.47	
13	Dawson Industrial - Earlington	Distribution*	69.00	4.16	
14	Dayhoit	Distribution*	69.00	12.47	
15	Days Branch	Distribution*	69.00	12.47	
16	Dayton - Walther - Carrollton	Distribution*	138.00	12.47	
17	Delaplain - Georgetown	Distribution*	69.00	12.47	
18	Delaplain - Georgetown	Distribution*	69.00	13.80	
19	Denham Street - Somerset	Distribution*	69.00	12.47	
20	Detroit Harvester - Paris	Distribution*	69.00	12.47	
21	Donerail - Lexington	Distribution*	69.00	12.47	
22	Dorchester - Norton	Distribution*	69.00	22.00	
23	Dorchester - Norton	Distribution*	69.00	34.50	
24	Dorchester - Norton	Distribution*	69.00	12.47	
25	Dow Corning - Carrollton	Distribution*	69.00	12.47	
26	Dozier Heights	Distribution*	69.00	12.47	
27	Earlington - Earlington	Distribution*	69.00	34.50	
28	Earlington - Earlington	Distribution*	69.00	12.47	
29	Earlington - Earlington	Distribution*	69.00	4.16	
30	East Bernstadt - London	Distribution*	69.00	12.47	
31	East Stone - Big Stone Gap	Distribution*	69.00	12.47	
32	Eastland - Lexington	Distribution*	69.00	12.47	
33	Eastview	Distribution*	69.00	12.47	
34	Eddyville	Distribution*	69.00	12.47	
35	Eddyville Prison	Distribution*	69.00	12.47	
36	Elizabethtown Industrial - Elizabethtown	Distribution*	69.00	12.47	
37	Eminence - Shelbyville	Distribution*	69.00	12.47	
38	Esserville - Norton	Distribution*	69.00	12.47	
39	Etown #2 - Elizabethtown	Distribution*	69.00	12.47	
40	Etown #3 - Elizabethtown	Distribution*	69.00	12.47	

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1	Etown #4 - Elizabethtown	Distribution*	69.00	12.47	
2	Etown #5 - Elizabethtown	Distribution*	69.00	12.47	
3	Etown West - Elizabethtown	Distribution*	69.00	12.47	
4	Evarts	Distribution*	69.00	12.47	
5	Ewington - Mt. Sterling	Distribution*	69.00	12.47	
6	Fairfield - Fairfield	Distribution*	69.00	12.47	
7	Farmers	Distribution*	69.00	12.47	
8	Ferguson South - Somerset	Distribution*	69.00	12.47	
9	Flemingsburg	Distribution*	138.00	12.47	
10	Florida Tile - Lawrenceburg	Distribution*	69.00	12.47	
11	FMC - Lexington	Distribution*	69.00	12.47	
12	Forrestdale	Distribution*	69.00	12.47	
13	Forks of Elkhorn - Georgetown	Distribution*	34.50	12.47	
14	Frankfort - Frankfort	Distribution*	69.00	34.50	
15	Gates Rubber	Distribution*	69.00	2.40	
16	GE Lamp Works - Lexington	Distribution*	69.00	4.16	
17	Georgetown - Georgetown	Distribution*	69.00	12.47	
18	Ghent Plant	Distribution*	138.00	13.20	
19	Green River Steel	Distribution*	69.00	12.47	
20	Green River	Distribution*	69.00	34.50	
21	Greensburg - Campbellsville	Distribution*	69.00	12.47	
22	Greenville 12KV - Muhlenburg	Distribution*	69.00	12.47	
23	Greenville 4KV - Muhlenburg	Distribution*	69.00	4.16	
24	Greenville North - Muhlenburg	Distribution*	69.00	12.47	
25	Haefling - Lexington	Distribution*	138.00	12.47	
26	Haley - Lexington	Distribution*	69.00	12.47	
27	Hamblin - Pennington Gap	Distribution*	69.00	12.47	
28	Hanson - Earlington	Distribution*	69.00	12.47	
29	Hardesty - Earlington	Distribution*	69.00	34.50	
30	Harlan - Harlan	Distribution*	69.00	12.47	
31	Harlan Wye - Harlan	Distribution*	69.00	12.47	
32	Harrodsburg East - Harrodsburg	Distribution*	69.00	12.47	
33	Harrodsburg Industrial - Harrodsburg	Distribution*	69.00	12.47	
34	Harrodsburg North	Distribution*	69.00	12.47	
35	Hartford	Distribution*	69.00	4.16	
36	Higby Mill - Lexington	Distribution*	138.00	12.47	
37	Higby Mill - Lexington	Distribution*	69.00	12.47	
38	Highsplint - Harlan	Distribution*	69.00	12.47	
39	Hodgenville 12KV	Distribution*	69.00	12.47	
40	Hoover 1 - Georgetown	Distribution*	69.00	12.47	

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1	Hopewell - Corbin	Distribution*	69.00	12.47	
2	Horse Cave	Distribution*	69.00	12.47	
3	Horse Cave Industrial - Horse Cave	Distribution*	69.00	12.47	
4	Hughes Lane - Lexington	Distribution*	69.00	12.47	
5	Hume Road	Distribution*	69.00	12.47	
6	IBM - Lexington	Distribution*	69.00	12.47	
7	IBM North	Distribution*	138.00	12.47	
8	Imboden - Norton	Distribution*	69.00	34.50	
9	Innovation Drive	Distribution*	138.00	12.47	
10	Irvine - Richmond	Distribution*	69.00	12.47	
11	Joyland - Lexington	Distribution*	69.00	12.47	
12	Kawneer - Cynthiana	Distribution*	69.00	12.47	
13	Kentenia	Distribution*	69.00	12.47	
14	Kenton - Maysville	Distribution*	69.00	12.47	
15	Kentucky State Hospital	Distribution*	69.00	12.47	
16	Kentucky River	Distribution*	69.00	4.16	
17	LaGrange East	Distribution*	69.00	12.47	
18	LaGrange - Penal - LaGrange	Distribution*	69.00	12.47	
19	Lakeshore - Lexington	Distribution*	69.00	12.47	
20	Lancaster - Danville	Distribution*	69.00	4.16	
21	Lansdowne - Lexington	Distribution*	69.00	12.47	
22	Lawrenceburg - Lawrenceburg	Distribution*	69.00	12.47	
23	Lebanon - Lebanon	Distribution*	69.00	12.47	
24	Lebanon East	Distribution*	69.00	12.47	
25	Lebanon Industrial	Distribution*	69.00	12.47	
26	Lebanon South - Lebanon	Distribution*	69.00	12.47	
27	Lebanon Junction	Distribution*	161.00	12.47	
28	Lebanon West	Distribution*	138.00	12.47	
29	Leitchfield - Leitchfield	Distribution*	69.00	12.47	
30	Leitchfield East - Leitchfield	Distribution*	69.00	12.47	
31	Lemons Mill - Georgetown	Distribution*	69.00	12.47	
32	Lexington Water Company	Distribution*	69.00	12.47	
33	Lexington Water Company	Distribution*	69.00	4.16	
34	Lexington Plant - Lexington	Distribution*	69.00	4.16	
35	Liberty - Liberty	Distribution*	69.00	12.47	
36	Liberty Road - Lexington	Distribution*	69.00	12.47	
37	Liggett	Distribution*	69.00	12.47	
38	Lockport	Distribution*	138.00	12.47	
39	London - London	Distribution*	69.00	12.47	
40	Loudon Ave. - Lexington	Distribution*	138.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Madisonville GE	Distribution*	69.00	12.47	
2	Madisonville Hospital	Distribution*	69.00	12.47	
3	Madisonville North	Distribution*	69.00	12.47	
4	Madisonville West	Distribution*	69.00	12.47	
5	Madisonville East	Distribution*	69.00	12.47	
6	Manchester South	Distribution*	69.00	12.47	
7	Marion South - Marion	Distribution*	69.00	12.47	
8	Maysville East - Maysville	Distribution*	69.00	4.16	
9	Maysville Mid - Maysville	Distribution*	69.00	4.16	
10	McCoy Avenue	Distribution*	69.00	12.47	
11	McKee Road	Distribution*	69.00	12.47	
12	Meldrum - Middlesboro	Distribution*	69.00	12.47	
13	Metal & Thermit - Carrollton	Distribution*	69.00	12.47	
14	Middlesboro #1	Distribution*	69.00	12.47	
15	Middlesboro #2	Distribution*	69.00	12.47	
16	Midway - Versailles	Distribution*	138.00	12.47	
17	Mill Creek	Distribution*	69.00	12.47	
18	Minor Farm	Distribution*	69.00	12.47	
19	Morehead - Morehead	Distribution*	69.00	12.47	
20	Morehead - Morehead	Distribution*	69.00	4.16	
21	Morehead East - Morehead	Distribution*	69.00	4.16	
22	Morehead West - Morehead	Distribution*	69.00	12.47	
23	Morganfield City - Morganfield	Distribution*	69.00	4.16	
24	Morganfield Industrial - Morganfield	Distribution*	69.00	12.47	
25	Mt. Sterling - Mt. Sterling	Distribution*	69.00	12.47	
26	Mt. Vernon - Mt. Vernon	Distribution*	69.00	12.47	
27	Muhlenburg Prison - Muhlenburg	Distribution*	69.00	12.47	
28	Munfordville	Distribution*	69.00	12.47	
29	New Haven	Distribution*	69.00	12.47	
30	Newtown	Distribution*	69.00	12.47	
31	Norton East - Norton	Distribution*	69.00	12.47	
32	Nortonville	Distribution*	34.50	12.47	
33	Oakhill - Earlington	Distribution*	69.00	34.50	
34	Okonite - Richmond	Distribution*	69.00	12.47	
35	Owingsville	Distribution*	69.00	12.47	
36	Oxford - Georgetown	Distribution*	69.00	12.47	
37	Paris - Paris	Distribution*	69.00	12.47	
38	Parker Seal - Winchester	Distribution*	69.00	12.47	
39	Parkers Mill	Distribution*	69.00	12.47	
40	Pepper Pike - Georgetown	Distribution*	34.50	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Picadome - Lexington	Distribution*	69.00	12.47	
2	Pineville	Distribution*	69.00	12.47	
3	Pocket - Norton	Distribution*	69.00	34.50	
4	Poor Valley - Pennington Gap	Distribution*	69.00	12.47	
5	Powderly - Muhlenburg	Distribution*	69.00	12.47	
6	Princeton - Princeton	Distribution*	69.00	34.50	
7	Proctor & Gamble	Distribution*	69.00	4.16	
8	Race Street - Lexington	Distribution*	69.00	12.47	
9	Race Street - Lexington	Distribution*	69.00	4.16	
10	Radcliff - Radcliff	Distribution*	69.00	12.47	
11	Radcliff South - Radcliff	Distribution*	69.00	12.47	
12	Red House	Distribution*	69.00	12.47	
13	Reynolds - Lexington	Distribution*	138.00	12.47	
14	Richmond	Distribution*	69.00	12.47	
15	Richmond #2	Distribution*	69.00	12.47	
16	Richmond #3 (EKU)	Distribution*	69.00	12.47	
17	Richmond East	Distribution*	69.00	12.47	
18	Richmond Industrial	Distribution*	69.00	12.47	
19	Richmond South	Distribution*	69.00	12.47	
20	Rineyville	Distribution*	69.00	12.47	
21	Robbins	Distribution*	69.00	12.47	
22	Rockwell - Winchester	Distribution*	69.00	12.47	
23	Rogers Gap	Distribution*	69.00	12.47	
24	Rogersville - Radcliff	Distribution*	69.00	12.47	
25	Rose Hill	Distribution*	69.00	12.47	
26	Rumsey - Earlington	Distribution*	69.00	34.50	
27	Russell Springs	Distribution*	69.00	12.47	
28	Salem - Earlington	Distribution*	69.00	34.50	
29	Shadrack	Distribution*	69.00	12.47	
30	Shannon Run	Distribution*	69.00	12.47	
31	Sharon - Augusta	Distribution*	69.00	12.47	
32	Shavers Chapel	Distribution*	69.00	12.47	
33	Shawnee Gas	Distribution*	69.00	12.47	
34	Shelbyville North	Distribution*	69.00	12.47	
35	Shelbyville East	Distribution*	69.00	12.47	
36	Shelbyville South	Distribution*	69.00	12.47	
37	Shun Pike	Distribution*	69.00	12.47	
38	Simpsonville - Shelbyville	Distribution*	69.00	12.47	
39	Somerset #2	Distribution*	69.00	4.16	
40	Somerset #3	Distribution*	69.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	Somerset South	Distribution*	69.00	12.47	
2	Sonora	Distribution*	69.00	12.47	
3	Springfield - Campbellsville	Distribution*	69.00	12.47	
4	St. Paul	Distribution*	69.00	12.47	
5	Stamping Ground	Distribution*	34.50	12.47	
6	Stanford	Distribution*	69.00	12.47	
7	Stanford North	Distribution*	69.00	12.47	
8	Stonewall - Lexington	Distribution*	69.00	12.47	
9	Sylvania - Winchester	Distribution*	69.00	12.47	
10	Taylorsville - Shelbyville	Distribution*	69.00	12.47	
11	Toms Creek	Distribution*	69.00	4.16	
12	Toyota North	Distribution*	138.00	13.20	
13	Toyota South	Distribution*	138.00	13.20	
14	Trafton Ave. - Lexington	Distribution*	69.00	12.47	
15	Trafton Ave. - Lexington	Distribution*	69.00	4.16	
16	UK Scott Street	Distribution*	69.00	12.47	
17	UK Medical Center - Lexington	Distribution*	69.00	12.47	
18	UK West - Lexington	Distribution*	69.00	13.09	
19	Union Underwear - Russell Springs	Distribution*	69.00	12.47	
20	Vaksdahl Avenue	Distribution*	69.00	12.47	
21	Verda - Harlan	Distribution*	69.00	12.47	
22	Versailles West - Versailles	Distribution*	69.00	12.47	
23	Versailles Bypass - Versailles	Distribution*	69.00	12.47	
24	Viley Road - Lexington	Distribution*	138.00	12.47	
25	Vine Street - Lexington	Distribution*	69.00	12.47	
26	Waco	Distribution*	69.00	12.47	
27	Waitsboro - Somerset	Distribution*	69.00	12.47	
28	Warsaw East - Owenton	Distribution*	69.00	12.47	
29	West Hickman - Lexington	Distribution*	69.00	12.47	
30	West High Street - Lexington	Distribution*	69.00	12.47	
31	Westvaco	Distribution*	69.00	13.80	
32	Whitley	Distribution*	69.00	12.47	
33	Wickliffe	Distribution*	69.00	13.80	
34	Wilson Downing - Lexington	Distribution*	69.00	12.47	
35	Williamsburg South - Williamsburg	Distribution*	69.00	12.47	
36	Wilmore - Versailles	Distribution*	69.00	12.47	
37	Winchester Industrial - Winchester	Distribution*	69.00	12.47	
38	Winchester Water	Distribution*	69.00	12.47	
39	Wise - Norton	Distribution*	69.00	12.47	
40	Woodlawn	Distribution*	69.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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	191 Stations Less Than 10 MVa				
2					
3	Total Distribution		21206.00	3768.33	
4					
5	* Unattended				
6					
7					
8	Summary				
9	Transmission 142				
10	Distribution 469				
11	Total 611				
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
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29					
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32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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
186	2		NONE			2
448	1		NONE			3
150	1		NONE			4
56	1		NONE			5
56	1		NONE			6
			NONE			7
94	1		NONE			8
			NONE			9
			NONE			10
56	1		NONE			11
			NONE			12
			NONE			13
			NONE			14
			NONE			15
			NONE			16
34	1		NONE			17
			NONE			18
150	1		NONE			19
			NONE			20
			NONE			21
			NONE			22
			NONE			23
448	1		NONE			24
			NONE			25
50	1		NONE			26
187	2		NONE			27
			NONE			28
93	1		NONE			29
			NONE			30
			NONE			31
112	1		NONE			32
112	1		NONE			33
			NONE			34
112	1		NONE			35
			NONE			36
			NONE			37
			NONE			38
			NONE			39
187	2		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
150	1		NONE			1
224	2		NONE			2
187	2		NONE			3
149	1		NONE			4
			NONE			5
			NONE			6
149	1		NONE			7
61	1		NONE			8
299	2		NONE			9
			NONE			10
			NONE			11
450	1		NONE			12
448	1		NONE			13
			NONE			14
			NONE			15
93	1		NONE			16
261	2		NONE			17
312	3	1	NONE			18
90	1		NONE			19
149	1		NONE			20
448	1		NONE			21
334	2		NONE			22
			NONE			23
			NONE			24
94	1		NONE			25
344	3		NONE			26
			NONE			27
			NONE			28
			NONE			29
149	1		NONE			30
			NONE			31
145	2		NONE			32
			NONE			33
			NONE			34
149	1		NONE			35
200	1		NONE			36
			NONE			37
112	1		NONE			38
100	6		NONE			39
			NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
93	1		NONE			1
			NONE			2
			NONE			3
			NONE			4
			NONE			5
262	2	2	NONE			6
			NONE			7
			NONE			8
			NONE			9
400	2		NONE			10
			NONE			11
			NONE			12
			NONE			13
			NONE			14
112	1		NONE			15
			NONE			16
450	1		NONE			17
			NONE			18
			NONE			19
			NONE			20
			NONE			21
			NONE			22
93	1		NONE			23
			NONE			24
150	1		NONE			25
560	1		NONE			26
504	1		NONE			27
299	2		NONE			28
			NONE			29
112	1		NONE			30
112	1		NONE			31
187	1		NONE			32
448	1		NONE			33
			NONE			34
			NONE			35
93			NONE			36
			NONE			37
151	2		NONE			38
93	1		NONE			39
93	1		NONE			40

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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
			NONE			2
			NONE			3
			NONE			4
50	1		NONE			5
			NONE			6
89	2		NONE			7
			NONE			8
			NONE			9
			NONE			10
90	1		NONE			11
112	1		NONE			12
			NONE			13
			NONE			14
			NONE			15
120	1		NONE			16
112	1		NONE			17
392	3		NONE			18
450	1		NONE			19
112	1		NONE			20
			NONE			21
56	1		NONE			22
448	1		NONE			23
			NONE			24
93	1		NONE			25
			NONE			26
			NONE			27
			NONE			28
13964	95	3				29
						30
22	1		NONE			31
20	1		NONE			32
22	1		NONE			33
22	1		NONE			34
14	1		NONE			35
22	1		NONE			36
36	2		NONE			37
22	1		NONE			38
11	1		NONE			39
28	2		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
20	2		NONE			1
14	1		NONE			2
14	1		NONE			3
22	1		NONE			4
45	2		NONE			5
11	1		NONE			6
14	1		NONE			7
14	1		NONE			8
22	1		NONE			9
14	2		NONE			10
42	3		NONE			11
28	1		NONE			12
45	2		NONE			13
22	1		NONE			14
22	1		NONE			15
11	1		NONE			16
22	1		NONE			17
67	3		NONE			18
14	1		NONE			19
14	1		NONE			20
14	1		NONE			21
11	1		NONE			22
28	2		NONE			23
14	1		NONE			24
45	2		NONE			25
22	1		NONE			26
14	2		NONE			27
22	1		NONE			28
22	1		NONE			29
19	2		NONE			30
11	1		NONE			31
14	1		NONE			32
14	1		NONE			33
14	1		NONE			34
37	1		NONE			35
22	1		NONE			36
11	1		NONE			37
14	1		NONE			38
14	1		NONE			39
36	2		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
25	2		NONE			1
56	2	4	NONE			2
15	7		NONE			3
29	2		NONE			4
20	2		NONE			5
14	1		NONE			6
29	2		NONE			7
29	2		NONE			8
45	2		NONE			9
14	1		NONE			10
22	1		NONE			11
14	1		NONE			12
14	1		NONE			13
11	1		NONE			14
14	1		NONE			15
14	1		NONE			16
14	1		NONE			17
28	1		NONE			18
14	1		NONE			19
22	1		NONE			20
14	1		NONE			21
28	1		NONE			22
14	1		NONE			23
14	1		NONE			24
14	1		NONE			25
14	1		NONE			26
20	1		NONE			27
14	1		NONE			28
3	3		NONE			29
14	1		NONE			30
25	2		NONE			31
22	1		NONE			32
11	1		NONE			33
14	1		NONE			34
11	1		NONE			35
22	1		NONE			36
28	2		NONE			37
22	1		NONE			38
45	2		NONE			39
33	2		NONE			40

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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.
22	1		NONE			1
14	1		NONE			2
22	1		NONE			3
11	1		NONE			4
36	2		NONE			5
14	1		NONE			6
11	1		NONE			7
14	1		NONE			8
14	1		NONE			9
14	1		NONE			10
22	1		NONE			11
14	1		NONE			12
14	1		NONE			13
20	1		NONE			14
11	1		NONE			15
14	1		NONE			16
21	2		NONE			17
56	2		NONE			18
25	2		NONE			19
17	1		NONE			20
14	1		NONE			21
14	1		NONE			22
11	1		NONE			23
14	1		NONE			24
39	1		NONE			25
14	1		NONE			26
14	1		NONE			27
22	1		NONE			28
13	1		NONE			29
21	2		NONE			30
28	2		NONE			31
20	2		NONE			32
14	1		NONE			33
14	1		NONE			34
11	1		NONE			35
37	1		NONE			36
22	1		NONE			37
14	1		NONE			38
19	2		NONE			39
22	1		NONE			40

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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.
28	2		NONE			1
28	2		NONE			2
45	2		NONE			3
14	1		NONE			4
22	1		NONE			5
75	2		NONE			6
34	1		NONE			7
37	1	1	NONE			8
75	2		NONE			9
14	1		NONE			10
36	2		NONE			11
14	1		NONE			12
11	1		NONE			13
28	2	1	NONE			14
11	1		NONE			15
35	3		NONE			16
36	2		NONE			17
22	1		NONE			18
75	2		NONE			19
14	1		NONE			20
75	2		NONE			21
45	2		NONE			22
14	1		NONE			23
28	2		NONE			24
11	1		NONE			25
14	1		NONE			26
45	2		NONE			27
14	1		NONE			28
14	1		NONE			29
14	1		NONE			30
45	2		NONE			31
45	2		NONE			32
11	1		NONE			33
28	2		NONE			34
14	1		NONE			35
37	1		NONE			36
11	1		NONE			37
11	1		NONE			38
45	2		NONE			39
37	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	
22	1		NONE			1
14	1		NONE			2
22	1		NONE			3
22	1		NONE			4
14	1		NONE			5
14	1		NONE			6
14	1		NONE			7
11	1		NONE			8
14	1		NONE			9
14	1		NONE			10
14	1		NONE			11
14	1		NONE			12
14	1		NONE			13
35	3		NONE			14
35	3		NONE			15
14	1		NONE			16
11	1		NONE			17
14	1		NONE			18
14	1		NONE			19
11	1		NONE			20
11	1		NONE			21
11	1		NONE			22
11	1		NONE			23
14	1		NONE			24
14	1		NONE			25
14	1		NONE			26
14	1		NONE			27
11	1		NONE			28
11	1		NONE			29
14	1		NONE			30
14	1		NONE			31
14	1		NONE			32
20	1		NONE			33
36	2		NONE			34
14	1		NONE			35
28	2		NONE			36
28	2		NONE			37
22	1		NONE			38
45	2		NONE			39
14	1		NONE			40

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/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.
45	2		NONE			1
28	2		NONE			2
25	4		NONE			3
14	1		NONE			4
14	1		NONE			5
13	1		NONE			6
14	1		NONE			7
14	1		NONE			8
21	2		NONE			9
22	1		NONE			10
11	1		NONE			11
14	1		NONE			12
77	2		NONE			13
45	2		NONE			14
22	1		NONE			15
45	2		NONE			16
22	1		NONE			17
22	1		NONE			18
22	1		NONE			19
14	1		NONE			20
11	1		NONE			21
22	1		NONE			22
22	1		NONE			23
22	1		NONE			24
11	1		NONE			25
13	1		NONE			26
14	1		NONE			27
14	1		NONE			28
11	1		NONE			29
14	1		NONE			30
14	1		NONE			31
14	1		NONE			32
15	1		NONE			33
22	1		NONE			34
45	2		NONE			35
36	2		NONE			36
14	1		NONE			37
25	2		NONE			38
14	1		NONE			39
14	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)	
14	1		NONE			1
11	1		NONE			2
25	2		NONE			3
45	2		NONE			4
14	1		NONE			5
14	1		NONE			6
14	1		NONE			7
37	1		NONE			8
26	2		NONE			9
14	1		NONE			10
11	1		NONE			11
84	3	1	NONE			12
112	4		NONE			13
22	1		NONE			14
14	1		NONE			15
37	1		NONE			16
75	2		NONE			17
42	2		NONE			18
28	2		NONE			19
14	1		NONE			20
14	1		NONE			21
22	1		NONE			22
45	2		NONE			23
39	1		NONE			24
20	2		NONE			25
14	1		NONE			26
14	1		NONE			27
14	1		NONE			28
45	2		NONE			29
28	2		NONE			30
67	3		NONE			31
11	1		NONE			32
14	1		NONE			33
45	2		NONE			34
25	2		NONE			35
18	2		NONE			36
22	1		NONE			37
14	1		NONE			38
22	1		NONE			39
14	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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.
870	256	128	NONE			1
						2
7492	647	135				3
						4
						5
						6
						7
						8
13964	95	6				9
7492	647	135				10
21456	742	141				11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
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						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) __ A Resubmission	/ /	2017/Q4

FOOTNOTE DATA

Schedule Page: 426.11   Line No.: 1   Column: h

128 spare transformers are stored at various company locations.

Bear Track	1
Big Stone Gap Storeroom	8
Danville Substation Department	13
Earlington Substation Department	54
Eastland Storage Department	9
Lexington Substation Department	17
Midway Storeroom	2
Pineville Substation Department	24
	128

Schedule Page: 426.11   Line No.: 9   Column: h

Three spare transformers are stored. One each at Earlington Substation Department, Edwards Movers Lot, and Pineville Substation Department.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Capital Expenditures	Louisville Gas and Electric Company	see footnote	9,834,777
3	Direct-Indirect Labor	Louisville Gas and Electric Company	see footnote	20,309,397
4	Equipment and Facilities	Louisville Gas and Electric Company	see footnote	927,478
5	Office and Administrative Services	Louisville Gas and Electric Company	see footnote	21,226
6	Materials and Fuels	Louisville Gas and Electric Company	see footnote	76,264
7	Outside Services	Louisville Gas and Electric Company	see footnote	487,692
8	Transmission	Louisville Gas and Electric Company	see footnote	182,171
9				
10	Capital Expenditures	LG&E and KU Services Company	see footnote	43,024,186
11	Direct-Indirect Labor	LG&E and KU Services Company	see footnote	103,033,871
12	Equipment and Facilities	LG&E and KU Services Company	see footnote	15,379,753
13	Office and Administrative Services	LG&E and KU Services Company	see footnote	6,351,999
14	Materials	LG&E and KU Services Company	see footnote	3,035,139
15	Outside Services	LG&E and KU Services Company	see footnote	18,083,707
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Capital Expenditures	Louisville Gas and Electric Company	see footnote	2,510,443
22	Direct-Indirect Labor	Louisville Gas and Electric Company	see footnote	895,168
23	Equipment and Facilities	Louisville Gas and Electric Company	see footnote	410,539
24	Office and Administrative Services	Louisville Gas and Electric Company	see footnote	22,297
25	Materials and Fuels	Louisville Gas and Electric Company	see footnote	135,164
26	Outside Services	Louisville Gas and Electric Company	see footnote	252,024
27	Transmission	Louisville Gas and Electric Company	see footnote	599,125
28				
29	Capital Expenditures	LG&E and KU Services Company	see footnote	259,307
30	Direct-Indirect Labor	LG&E and KU Services Company	see footnote	2,263,421
31	Equipment and Facilities	LG&E and KU Services Company	see footnote	506,898
32	Office and Administrative Services	LG&E and KU Services Company	see footnote	30,463
33	Materials	LG&E and KU Services Company	see footnote	303,282
34	Outside Services	LG&E and KU Services Company	see footnote	135,950
35				
36	Equipment and Facilities	LG&E and KU Energy LLC	see footnote	274,519
37				
38				
39				
40				
41				
42	See footnote for allocation process.			
1	**Non-power Goods or Services Provided by Affiliated**			
2	Capital Expenditures	PPL Services Corporation	see footnote	238,883

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/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)
3	Direct-Indirect Labor	PPL Services Corporation	see footnote	765,552
4	Equipment and Facilities	PPL Services Corporation	see footnote	172,057
5	Office and Administrative Services	PPL Services Corporation	see footnote	467,695
6	Outside Services	PPL Services Corporation	see footnote	823,420
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18	See footnote for allocation process			
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
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39				
40				
41				
42				

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

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: 173, 182.3, 184, 408.1, 426.4, 426.5, 500-502, 505, 506, 510-514, 544, 546, 548, 549, 551-554, 556, 560, 561.1, 566, 570, 580, 583, 586, 588, 592, 595, 901, 903, 908, 920, 921, 925, 926 and 935

Schedule Page: 429 Line No.: 4 Column: c
Accounts charged include: 143, 163, 165, 173, 183, 184, 426.4, 426.5, 500-502, 506, 510-514, 544, 549, 554, 556, 560, 561.1, 562, 563, 566, 570, 571, 573, 580, 582, 583, 586, 588, 592-595, 598, 901-903, 907, 908, 921, 931 and 935

Schedule Page: 429 Line No.: 5 Column: c
Accounts charged include: 426.4, 426.5, 500, 506, 510, 511, 513, 554, 561.1, 570, 580, 586, 588, 901, 903, 907, 921 and 930.2

Schedule Page: 429 Line No.: 6 Column: c
Accounts charged include: 163, 184, 188, 500, 510-514, 566, 570, 580, 588, 593, 902, 921 and 923

Schedule Page: 429 Line No.: 7 Column: c
Accounts charged include: 163, 184, 188, 500, 506, 510, 511, 513, 553, 554, 562, 566, 570, 580, 582, 588, 592, 594, 921, 923 and 935

Schedule Page: 429 Line No.: 8 Column: c
Accounts charged include: 565

Schedule Page: 429 Line No.: 10 Column: c
Accounts charged include: 107 and 108

Schedule Page: 429 Line No.: 11 Column: c
Accounts charged include: 143, 163, 173, 183, 184, 236, 408.1, 426.4, 426.5, 500-502, 506, 510-513, 544, 549, 554, 556, 560, 561.1, 561.2, 561.3, 561.5, 561.6, 562, 563, 566, 570, 571, 573, 580-583, 586, 588, 590, 592, 593, 598, 901-903, 905, 907, 908, 920, 921, 925, 926, 930.2 and 935

Schedule Page: 429 Line No.: 12 Column: c
Accounts charged include: 143, 163, 165, 183, 184, 188, 421, 426.4, 426.5, 500-502, 506, 510, 511, 513, 514, 544, 554, 556, 560, 561.1, 561.5, 562, 563, 566, 570, 571, 573, 580, 582, 583, 586, 588, 592, 593, 901-903, 907, 908, 910, 921, 923, 925, 930.2, 931 and 935

Schedule Page: 429 Line No.: 13 Column: c
Accounts charged include: 184, 186, 188, 236, 408.1, 421, 426.4, 426.5, 500-502, 506, 510-514, 544, 549, 554, 556, 560, 561.1, 561.3, 561.5, 562, 563, 566, 570, 571, 573, 580-583, 586, 588, 590, 592, 593, 598, 901-903, 905, 907, 908, 910, 920, 921, 925, 930.2 and 935

Schedule Page: 429 Line No.: 14 Column: c
Accounts charged include: 163, 184, 188, 426.5, 500-502, 505, 506, 510-512, 514, 553, 554, 560, 561.1, 566, 570, 573, 580, 586, 588, 592, 593, 598, 903, 907, 910, 921, 923, 930.2 and 935

Schedule Page: 429 Line No.: 15 Column: c
Accounts charged include: 163, 165, 184, 186, 188, 426.4, 426.5, 500-502, 505, 506, 510-512, 514, 553, 554, 556, 560, 561.1, 561.2, 561.5, 566, 570, 571, 573, 580, 582, 583, 586, 588, 592, 593, 598, 901, 903, 908-910, 921, 923, 928, 930.2 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: 173, 184, 408.1, 426.5, 500, 501, 510, 513, 546, 549, 551-554, 556, 560, 566, 570, 580, 583, 588, 593, 595, 901, 903, 920, 922, 925, 926 and 935

Schedule Page: 429 Line No.: 23 Column: c
Accounts charged include: 143, 163, 165, 173, 184, 416, 426.4, 426.5, 454, 456, 500-502, 506, 510-513, 546, 549, 553, 560, 562, 563, 566, 567, 570, 571, 573, 580, 582-584, 586, 588, 590, 592-594, 596, 818, 851, 871, 878, 901, 903, 921 and 935

Schedule Page: 429 Line No.: 24 Column: c

Name of Respondent Kentucky Utilities Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Accounts charged include: 184, 426.5, 500, 502, 506, 510, 513, 561.1, 566, 570, 583, 586, 588, 590, 593, 880, 901, 903, 920, 921 and 935

Schedule Page: 429 Line No.: 25 Column: c

Accounts charged include: 163, 184, 186, 188, 500, 506, 510-514, 553, 566, 571, 593, 902, 921 and 923

Schedule Page: 429 Line No.: 26 Column: c

Accounts charged include: 184, 188, 500, 506, 510, 511, 553, 560, 562, 566, 570, 571, 580, 582, 880, 902, 921 and 923

Schedule Page: 429 Line No.: 27 Column: c

Accounts charged include: 456.1

Schedule Page: 429 Line No.: 29 Column: c

Accounts charged include: 107 and 108

Schedule Page: 429 Line No.: 30 Column: c

Accounts charged include: 163, 183, 184, 408.1, 426.4, 426.5, 500-502, 506, 510, 512, 513, 556, 560, 561.1, 561.2, 561.3, 561.5, 562, 563, 566, 570, 571, 573, 580, 581, 583, 586, 588, 590, 593, 901-903, 905, 907, 908, 920, 925, 926, 930.2 and 935

Schedule Page: 429 Line No.: 31 Column: c

Accounts charged include: 184

Schedule Page: 429 Line No.: 32 Column: c

Accounts charged include: 184, 921 and 935

Schedule Page: 429 Line No.: 33 Column: c

Accounts charged include: 184, 514 and 935

Schedule Page: 429 Line No.: 34 Column: c

Accounts charged include: 184

Schedule Page: 429 Line No.: 36 Column: c

Accounts charged include: 931

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Costs between Kentucky Utilities Company and Louisville Gas and Electric Company are either charged directly or are allocated by certain assignment methods described below that most accurately distribute the costs.

LG&E and KU Services Company (LKS) either directly charges or allocates 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 LKS and PPL Services are as follows:

Contract Ratio - Based on the sum of the physical amount (i.e. tons of coal, mmbtu of natural gas) of the contract for coal and natural gas fuel burned 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.

Corporate Information Security Ratio - This ratio allocates the cost of cyber security activities using an allocation consistent with the methodology used by third party insurers providing cyber security insurance to the organization. The methodology assigns

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a percentage of the premium based on the various risks (e.g., number of employees, the number of customers, etc.). The total of the percentages equals 100%. 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 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 and 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. The Departmental Charge Ratio will only be used with prior approval by the Controller when other applicable ratios would not result in the fair assignment of costs. 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.

Facilities Ratio – Based on a two-tiered approach with one tier based on the number of employees by department or line of business and the other tier based on the applicable department or line of business ratio. The numerator for the number of employees is the number of employees by department or line of business at the facility and the denominator is the total employees at the facility. The numerator and denominator for the applicable department or line of business for the service provided as described in this document. 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 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.

Network Users Ratio – Based on the number of IT network users at the end of the previous

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calendar year. A two-step assignment methodology is utilized to properly allocate costs to the proper legal entity. The numerator for the first step of this ratio is the total number of network users for each specific company, and the denominator is the total number of network users for all companies in which an allocator is assigned (i.e. LG&E, KU, LKS and PPL). For the second step, the ratio of LKS network users, to total network users will then be allocated to the other companies (LG&E, KU, and LKC) based on each company's ratio of LKS labor hours to total LKS labor hours. 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 LKS 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 LKS). For the second step, the ratio of LKS to total employees will then be allocated to the other companies (LG&E, KU and LKC) based on each company's ratio of labor hours to total labor hours. LKC has no employees, but non-utility related labor is charged to it. In some cases, the ratio may be calculated based on the number of employees at a specific location for the first step with the ratio of LKS to total employees being allocated based on labor hours of the employees at the specific location. 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

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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 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 number of transactions occurring in 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. The Controller's organization is responsible for maintaining and monitoring specific product/service methodology documentation for actual transactions related to LKS 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.

Ownership Percentages – Based on the contractual ownership percentages of jointly-owned generating units, information technology, facilities and other capital projects. This ratio is updated as a result of new jointly-owned capital projects and is based on the benefit to the respective company. The numerator is the specific company's forecasted usage. The denominator is the total forecasted usage of all respective companies.

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 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.

Revenue, Total Assets and Number of Employees Ratio – Based on an average of the revenue, total assets and number of employees ratios. 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

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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 and the denominator of which is for all operating 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.

Transmission Ratio –The Transmission Coordination Agreement (TCA) provides "the contractual basis for the coordinated planning, operation, and maintenance of the combined" LG&E and KU transmission system. Pursuant to the terms of the TCA, LG&E/KU "operate their transmission systems as a single control area." The TCA establishes cost and revenue allocations between LG&E and KU. The Transmission Ratio is based upon Schedule A (Allocation of Operating Expenses of the Transmission System Operator) of the TCA. Transmission System Operator Company allocation percentages are calculated during June of each year to be effective July 1st of each year using the previous year's summation of the Transmission Peak Demands as found in FERC Form 1 for Kentucky Utilities Company (KU) and Louisville Gas & Electric Company (LG&E) page 400 line 17(b).

Ultimate Users Ratio – Based on the number of ultimate users of an IT product or service (i.e., software, hardware, mobile devices, etc.) at the end of the previous calendar year. A two-step assignment methodology is utilized to properly allocate costs to the proper legal entity. The numerator for the first step of this ratio is the total number of ultimate users for each specific company, and the denominator is the total number of ultimate users for all companies in which an allocator is assigned (i.e. LG&E, KU, LKS and PPL). For the second step, the ratio of LKS ultimate users, to total ultimate users will then be allocated to the other companies (LG&E, KU, and LKC) based on each company's ratio of LKS labor hours to total LKS labor hours. 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.

Vehicle Cost Allocation 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

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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.

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Accounts charged include: 107

Schedule Page: 429.1 Line No.: 3 Column: c

Accounts charged include; 920 and 926

Schedule Page: 429.1 Line No.: 4 Column: c

Accounts charged include: 165 and 921

Schedule Page: 429.1 Line No.: 5 Column: c

Accounts charged include: 514, 921, 923 and 930.2

Schedule Page: 429.1 Line No.: 6 Column: c

Accounts charged include: 921, 923 and 930.2

Schedule Page: 429.1 Line No.: 18 Column: a

Costs from PPL Services Corporation are charged directly.

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Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(l)
Sponsoring Witness: Christopher M. Garrett

Description of Filing Requirement:

The annual report to shareholders or members and the statistical supplements covering the most recent two (2) years from the application filing date.

Response:

There are no annual reports to shareholders or members during the period referenced. KU does not publish a statistical supplement.

Federal securities rules generally require the delivery of annual reports to public shareholders when requesting their vote via certain proxy solicitations. During the period in question, the common stock of KU has been wholly-owned by LG&E and KU Energy LLC, which is a wholly-owned subsidiary of PPL Corporation.

Copies of the audited annual financial statements and other financial information of KU relating to the period described are provided in Filing Requirement 807 KAR 5:001 Section 16(7)(p), [Tab No. 46].

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(m)
Sponsoring Witness: Christopher M. Garrett

Description of Filing Requirement:

The current chart of accounts if more detailed than the Uniform System of Accounts chart prescribed by the commission.

Response:

See attached.

Oracle Account Setup Details

Account Number	Account Description
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
101126	PLANT IN SERVICE - ELECTRIC ARO ASSET RETIREMENT COST-CCR
101130	PROPERTY UNDER OPERATING LEASES
101131	PROPERTY UNDER FINANCING LEASES
101202	PLANT IN SERVICE - GAS FRANCHISES AND CONSENTS
101203	PLANT IN SERVICE - GAS MISC. INTANGIBLE PLANT
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
101700	PLANT IN SERVICE - CONTRA ASSET - PENSION
101701	PLANT IN SERVICE - CONTRA ASSET - OPEB
102001	ELECTRIC PLANT-PURCHASED OR SOLD
105001	PLT HELD FOR FUT USE
105002	PLANT HELD FOR FUTURE USE - LAND RIGHTS
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
106203	COMPL CONST NOT CL - GAS MISC. INTANGIBLE PLANT
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
107700	CONSTR WORK IN PROG - CONTRA ASSET - PENSION
107701	CONSTR WORK IN PROG - CONTRA ASSET - OPEB
108104	ACCUM. DEPR. - ELECTRIC LAND RIGHTS
108105	ACCUM. DEPR. - ELECTRIC STRUCTURES

Oracle Account Setup Details

Account Number	Account Description
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
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
108126	ACCUM. DEPR. - ELECTRIC ARO ASSET RETIREMENT COST-CCR
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
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.
108621	ACCUM. DEPR. - SALVAGE - COMMON EQUIPMENT
108622	ACCUM. DEPR. - SALVAGE - COMMON COMMUNICATION EQUIPMENT
108700	ACCUM DEPR - CONTRA ASSET - PENSION
108701	ACCUM DEPR - CONTRA ASSET - OPEB
108799	RWIP-ARO LEGAL
108899	RWIP-ARO-ECR CLEARING
108901	RETIREMENT - RWIP
111102	AMORTIZATION EXPENSE - ELECTRIC FRANCHISES AND CONSENTS
111103	AMORTIZATION EXPENSE - ELECTRIC INTANGIBLES
111104	ACCUM DEPR PROPERTY UNDER OPERATING LEASES
111105	ACCUM DEPR PROPERTY UNDER FINANCING LEASES
111202	AMORTIZATION EXPENSE - GAS FRANCHISES AND CONSENTS
111203	AMORTIZATON EXPENSE - GAS INTANGIBLES
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

Oracle Account Setup Details

Account Number	Account Description
121107	FURNITURE & FIXTURES
122001	ACCUM DEPR/DEPL
122007	ACCUM. DEPR. - ELECTRIC ARO ASSET RETIRMENT COST-EQUIPMENT
122207	FURNITURE & FIXTURES - ACCUM DEPRECIATION
123102	INVESTMENT IN LGE PA ADJS
123103	INVEST IN LGE
123104	INVEST IN LGE CAPITAL
123105	INVESTMENT IN KU
123108	INVEST IN LEM
123109	INVEST IN SERVCO
123116	INVEST IN WKE
123118	INVEST IN FCD LLC
123123	INVESTMENT IN OVEC
123124	INVESTMENT IN DHA
123125	INVEST IN LGE CAPITAL PA ADJS
123127	INVEST IN SERVCO PA ADJS
123128	INVEST IN WKE PA ADJS
123133	INVEST IN DOWNTOWN COMMERICAL LOAD FUND
123134	INVESTMENT IN SUBS - CURRENT-YEAR EQUITY IN EARNINGS
123175	INVESTMENT IN KU PA ADJS
123186	NOTES RECEIVABLE FROM LG&E AND KU ENERGY LLC NON-CURRENT
128023	PREPAID PENSION
128024	PREPAID PENSION - LG&E UNION PLAN
128026	COLLATERAL DEPOSIT - IR SWAPS
128027	RESTRICTED CASH - NON-CURRENT
128028	PREPAID POSTRETIREMENT
131024	CASH- BNY MELLON BANK
131033	US BANK - LGE - LOUISVILLE
131050	SUNDRY CASH COLLECT
131069	CASH CLEARING - CCS
131080	LGE - BANK OF AMERICA - EBOX
131090	CASH-BOA A/P - CLEARING
131091	CASH-BOA PAYROLL
131092	CASH-BOA FUNDING
131093	UNION BANK - LGE - TRANSCENTRA
131200	UNION BANK - KU - TRANSCENTRA
131204	KU - BANK OF AMERICA - EBOX
131227	US BANK - MASTER ROLL UP ACCOUNT
131235	BANK OF AMERICA (BANK DRAFTS) - KU LOUISVILLE
131236	US BANK - BARLOW 134-1
131237	US BANK - EARLINGTON 141-5
131238	US BANK - EDDYVILLE 150-1
131239	US BANK - GREENVILLE 161-2
131240	US BANK - MORGANFIELD 171-1
131241	US BANK - CAMPBELLSVILLE 222-2
131242	US BANK - MOREHEAD 342-2
131243	US BANK - PARIS 351-1
131244	US BANK - LONDON 421-2
131245	US BANK - MIDDLESBORO 431-1
131246	US BANK - HARLAN 441-2
131247	US BANK - SOMERSET 451-1
131248	US BANK - NORTON 761-2
131249	US BANK - PENNINGTON GAP 773-1
131250	US BANK - DANVILLE 211-2
131251	US BANK - RICHMOND 231-2
131252	US BANK - E-TOWN 241-1
131253	US BANK - SHELBYVILLE 251-2
131254	US BANK - LEXINGTON 311-9
131255	US BANK - GEORGETOWN 321-3
131256	US BANK - VERSAILLES 331-3
131257	US BANK - MT. STERLING 341-2
131258	US BANK - MAYSVILLE 361-1
131259	US BANK - CARROLLTON 371-2
131260	US BANK - WINCHESTER 385-3
135001	WORKING FUNDS
136005	TEMP INV-OTHER
136015	TEMPORARY INVESTMENT ACCOUNTS AT BANK OF AMERICA
136018	TEMP INV-FIDELITY INVESTMENTS-CASH UNRESTRICTED

Oracle Account Setup Details

Account Number	Account Description
136020	CLOSED 06/18 - TEMP INV-UBS-CASH UNRESTRICTED
136028	CLOSED 06/18 - TEMP INV-SUNTRUST
141004	NOTES RECEIVABLE - INDUSTRIAL AUTHORITY
141005	RESERVE FOR NOTES RECEIVABLE - INDUSTRIAL AUTHORITY
142001	CUST A/R-ACTIVE
142002	A/R - UNPOSTED CASH
142003	WHOLESALE SALES A/R
142004	TRANSMISSION RECEIVABLE
142012	ACCTS REC - MISC CUSTOMERS - SUNDRY
142999	CUST A/R KU SUSP CIS- ACCTG 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)
143024	A/R MUTUAL AID
143027	CLOSED 06/18 - INCOME TAX RECEIVABLE - FEDERAL
143028	INCOME TAX RECEIVABLE - STATE
143030	EMPLOYEE PAYROLL ADVANCES
143032	ACCTS REC - TAX REFUNDS
143036	SUSPENSE - PPL
143037	STATE INCOME TAX RECEIVABLE
143038	ACCTS REC - MISC PAYROLL
143040	ACCTS REC - WKE UNWIND - DISPATCH, IT ADHOC, & CENTURY
143041	COBRA/LTD BENEFITS - RECEIVABLE
143042	AR REFINED COAL
143043	ACCTS REC - REVENUE FROM CONTRACTS
143052	ACCOUNTS RECEIVABLE - IMEA/IMPA OFFSET
143053	LIQUIDATED DAMAGES/WARRANTY CLAIMS RECEIVABLE
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
144011	UNCOLL MISC A/R PROVISION
144014	UNCOLL A/R - WKE RESERVES
144015	UNCOLL A/R - LIQUIDATED DAMAGES
145011	N/R FROM LG&E - MONEY POOL
145012	N/R FROM KU - MONEY POOL
145013	N/R FROM LCC - MONEY POOL
145015	CLOSED 06/18 - N/R FROM LEM - MONEY POOL
145020	CLOSED 01/18 - NOTES RECEIVABLE FROM LKE - CURRENT
145021	CLOSED 06/18 - NOTES RECEIVABLE - PPL ENERGY FUNDING - CURRENT
145022	N/R FROM FCD - MONEY POOL
145023	N/R FROM WKE - MONEY POOL
145025	CLOSED 01/18 - NOTES RECEIVABLE FROM LG&E AND KU ENERGY LLC NON-CURRENT
145100	N/R FROM LKE PARENT - MONEY POOL
146006	NOTES RECEIVABLE FROM LKE - CURRENT
146048	CLOSED 03/18 -INTERCOMPANY DIVIDENDS RECEIVABLE FROM LG&E COMPANY
146049	INTERCOMPANY ADVANCE FROM LG&E
146050	INTERCOMPANY ADVANCE FROM KU
146053	INTERCOMPANY PENSION RECEIVABLE
146054	I/C RECEIVABLE - PPL ELECTRIC UTILITIES CORPORATION
146055	I/C INTEREST RECEIVABLE - PPL ENERGY FUNDING CURRENT
146056	CLOSED 03/18 - INTERCOMPANY DIVIDENDS RECEIVABLE FROM KU COMPANY
146057	I/C RECEIVABLE - PPL SERVICES CORPORATION
146058	I/C RECEIVABLE - PPL CORPORATION
146061	INTERCOMPANY INCOME TAX RECEIVABLE - FEDERAL
146067	I/C RECEIVABLE - PPL EU SERVICES CORPORATION
146070	I/C RECEIVABLE - PPL TRANSLINK
146100	INTERCOMPANY
151010	FUEL STK-LEASED CARS
151020	COAL PURCHASES - TONS - $
151021	COAL - BTU ADJ - BTU
151023	IN-TRANSIT COAL - TONS - $

Oracle Account Setup Details

Account Number	Account Description
151025	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - COAL PURCHASES - TONS - $
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 - GAL - $
151033	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - FUEL OIL (STAT ONLY)
151060	RAILCARS-OPER/MTCE
151061	GAS PIPELINE OPER/MTCE - MCF - $
151073	IN-TRANSIT COAL-MMBTU/IN-TRANSIT PET COKE <AUG 2009
151080	COAL BARGE SHUTTLING
154001	MATERIALS/SUPPLIES
154003	LIMESTONE
154004	CLOSED 06/18 - 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
158125	NOX ANNUAL ALLOWANCE INVENTORY
163011	STORES EXPENSE - GENERATION
163012	WAREHOUSE EXPENSES - GENERATION
163013	FREIGHT - GENERATION
163015	SALES TAX - GENERATION
163016	PHYS INVENT ADJUSTMT - GENERATION
163017	INVOICE PRICE VARIANCES - GENERATION
163101	OTHER - GENERATION
163201	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - STORES
164101	GAS STORED-CURRENT
165001	PREPAID INSURANCE
165002	PREPAID TAXES
165006	CLOSED 06/18 - PREPAID GAS FRANCH
165012	PREPAID LEASE
165013	PREPAID RIGHTS OF WAY
165018	PREPAID RISK MGMT AND WC
165025	PREPAID SALES & OTHER TAXES
165026	PREPAID ADP FUNDING
165100	PREPAID OTHER
165101	PREPAID IT CONTRACTS
165102	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - PREPAID INSURANCE
165201	PREPAID IT CONTRACTS-LT
165202	PREPAID POWELL LEASE-LT
165203	PREPAID RIGHTS OF WAY-LT
165204	PREPAID INSURANCE - LONG TERM
165900	PREPAID OTHER - INDIRECT
165950	PREPAID INSURANCE - INDIRECT
171001	INTEREST RECEIVABLE
172001	RENTS RECEIVABLE FOR POLE ATTACHMENTS
172002	LEASES RECEIVABLE
173001	ACCRUED UTIL REVENUE
173002	ACCRUED REVENUE - UNBILLED BEYOND THE METER
173005	ACCRUED WHOLESALE SALES REVENUE - UNBILLED
174001	MISC CURR/ACCR ASSET
181100	UAMORTIZED DEBT EXPENSE
181200	UNAMORTIZED DEBT EXPENSE REVOLVERS/LCS
181300	UNAMORTIZED DEBT EXPENSE BONDS
182305	REGULATORY ASSET - FAS 158 OPEB
182306	FUEL ADJUSTMENT CLAUSE
182307	ENVIRONMENTAL COST RECOVERY
182308	REG ASSET - GAS SUPPLY CLAUSE
182309	VA FUEL COMPONENT - JURISDICTIONAL CUSTOMERS (CURRENT)
182311	CLOSED 06/18 - FERC JURISDICTIONAL PENSION EXPENSE
182313	REG ASSET - PENSION GAIN-LOSS AMORTIZATION-15 YEAR
182315	REGULATORY ASSET - FAS 158 PENSION
182317	OTHER REGULATORY ASSETS ARO - GENERATION
182318	OTHER REG ASSETS ARO - TRANSMISSION
182320	WINTER STORM - ELECTRIC
182321	CLOSED 06/18 - MISO EXIT FEE

Oracle Account Setup Details

Account Number	Account Description
182325	OTHER REGULATORY ASSETS ARO - DISTRIBUTION
182326	OTHER REGULATORY ASSETS ARO - GAS
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)
182334	WIND STORM REGULATORY ASSET
182335	RATE CASE EXPENSES - ELECTRIC
182336	RATE CASE EXPENSES - GAS
182339	MOUNTAIN STORM - ELECTRIC
182342	WINTER STORM - GAS
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	CLOSED 06/18 - KCCS FUNDING - PRE-PPL MERGER CURRENT PORTION
182352	REG ASSET - LT INTEREST RATE SWAP
182353	CLOSED 06/18 - REG. ASSET - COAL CONTRACT - ST
182354	CLOSED 06/18 - REG. ASSET - COAL CONTRACT
182356	CLOSED 06/18 - VA FUEL COMPONENT - JURISDICTIONAL CUSTOMERS (NON-CURRENT)
182358	REG ASSET - UNAMORT DEBT EXP PAA
182359	CLOSED 06/18 - GENERAL MANAGEMENT AUDIT - ELECTRIC
182360	CLOSED 06/18 - GENERAL MANAGEMENT AUDIT - GAS
182361	2011 SUMMER STORM - ELECTRIC
182363	DSM COST RECOVERY - UNDER-RECOVERY
182365	GAS LINE TRACKER- REG ASSET
182366	REG ASSET - MUNI GEN TRUE UP
182367	REG ASSET - MUNI MISO EXIT FEE
182368	VA FUEL COMPONENT - NON-JURISDICTIONAL CUSTOMERS (CURRENT)
182369	GREEN RIVER REGULATORY ASSET
182370	REGULATORY ASSET - OST
182371	REG ASSET - FORWARD STARTING SWAPS SEP-2015
182372	OTHER REGULATORY ASSETS ARO - GENERATION - CCR
182373	REG. ASSET - OPEN ARO PONDS - KY
182374	REG. ASSET - OPEN ARO PONDS - VA
182375	REG. ASSET - OPEN ARO PONDS - FERC REMAINING MUNI
182376	REG. ASSET - OPEN ARO PONDS - FERC DEPARTING MUNI
182377	REG. ASSET - CLOSED ARO PONDS - KY
182378	REG. ASSET - CLOSED ARO PONDS - VA
182379	REG. ASSET - CLOSED ARO PONDS - FERC REMAINING MUNI
182380	REG. ASSET - CLOSED ARO PONDS - FERC DEPARTING MUNI
182381	REG ASSET - LT - BOA SWAP TERMINATION
182382	REG. ASSET - CLOSED ARO PONDS - PARIS
182383	REG. ASSET - OPEN ARO PONDS - PARIS
182384	REG ASSET - ASU 2017-07 - NON SERVICE COST - PENSION
182385	REG ASSET - ASU - 2017-07 - NON SERVICE COST - OPEB
182386	REG ASSET - PLANT OUTAGE NORMALIZATION
182387	OTHER REGULATORY ASSETS ARO - ECR/CCR
183201	OTH PREL SUR/INV-GAS
183301	PRELIM SURV/INV-ELEC
183302	PRELIMINARY SURV/INV ELEC - LT
184002	VACATION PAY
184011	HOLIDAY PAY
184021	SICK PAY
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	CLOSED 05/18 - PENSION SERVICE COST - BURDEN CLEARING
184097	FASB 106 (OPEB) SERVICE COST - BURDEN CLEARING
184098	FASB 112 - BURDEN CLEARING
184099	PENSION SERVICE COST - BURDEN CLEARING
184100	WALL STREET SUSPENSE ACCOUNT
184101	GROUP LIFE INSURANCE - BURDEN CLEARING
184104	DENTAL INSURANCE - BURDEN CLEARING

Oracle Account Setup Details

Account Number	Account Description
184105	MEDICAL INSURANCE - BURDEN CLEARING
184108	401K - BURDEN CLEARING
184109	RETIREMENT INCOME - BURDEN CLEARING
184119	CLOSED 05/18 - PENSION NON SERVICE COST - BURDEN CLEARING
184120	FASB 106 POST RETIREMENT NON SERVICE COST - BURDEN CLEARING
184121	OTHER BENEFITS - BURDEN CLEARING
184122	PENSION NON SERVICE COST - BURDEN CLEARING
184125	PAYROLL TAX CLEARING - FICA, STATE AND FED UNEMPLOYMENT
184130	LKS ALLOCATION CLEARING ACCOUNT
184135	ORACLE PROJECT BURDEN CLEARING ACCOUNT
184136	LKS ALLOC. CLEARING ACCOUNT FOR ALLOCATED CAPITAL
184140	MEDICAL PAYMENT HOLDING ACCT - (SERVCO ONLY)
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
184319	FUEL ADMINISTRATION VEHICLES
184320	TRANSPORTATION EXPENSE ALLOCATION - CLEARING
184450	CL ACC TO OTH DEF CR
184503	OPERATIONS - SIMPSONVILLE
184504	OPERATION-SSC
184505	MAINTENANCE-SSC
184506	MAINTENANCE - SIMPSONVILLE
184507	OPERATIONS - KU GENERAL OFFICE
184508	MAINTENANCE - KU GENERAL OFFICE
184509	OPERATIONS - LGE CENTER
184513	OTHER EXPENSES - LGE CENTER
184514	OPERATION-ESC
184515	MAINTENANCE-ESC
184516	OPERATION-BOC
184517	MAINTENANCE-BOC
184518	OPERATION-AUBURNDALE
184519	MAINT-AUBURNDALE
184521	OPERATIONS - MORGANFIELD
184522	MAINTENANCE - MORGANFIELD
184523	OPERATIONS - DIX DAM
184524	MAINTENANCE - DIX DAM
184525	OPERATIONS - EARLINGTON
184526	MAINTENANCE - EARLINGTON
184531	OPERATIONS - RIVERPORT
184532	MAINTENANCE - RIVERPORT
184533	OPERATIONS - PINEVILLE
184534	MAINTENANCE - PINEVILLE
184599	MISC FACILITIES ALLOCATION-OFFSET
184600	ENGINEERING OVERHEADS - GENERATION
184602	ENGINEERING OVERHEADS - DISTRIBUTION
184603	ENGINEERING OVERHEADS - RETAIL GAS
184605	ENGINEERING OVERHEADS - TRANSMISSION
184612	ENGINEERING OVERHEADS - DISTRIBUTION
184630	ENGINEERING OVERHEADS - GENERATION DIRECT
184650	CUSTOMER ADVANCES - CLEARING
184701	CLOSED 06/18 - EMPLOYEE ADVANCES - CLEARING
184702	IEXPENSE CREDIT CARD CLEARING
184730	LEASE PAYMENT - CLEARING
186001	MISC DEFERRED DEBITS
186004	FINANCING EXPENSE
186035	KEY MAN LIFE INSURANCE
186049	PRELIMINARY CELL SITE COSTS
186074	CANE RUN 7 LTPC ASSET
186075	BROWN 6 AND 7 LTSA ASSET
186505	GOODWILL
186548	CLOSED 06/18 - OTHER INTANGIBLE ASSETS - SHORT TERM

Oracle Account Setup Details

Account Number	Account Description
186549	OTHER INTANGIBLE ASSETS
186553	OTH INTANG ASSETS - OVEC PPA ENERGY CONTRACT
186556	OTH INTANG ASSETS - SO2 ALLOWANCES - CURRENT
186557	CLOSED 06/18 - OTH INTANG ASSETS - NOX OZONE ALLOWANCES - CURRENT
186558	CLOSED 06/18 - OTH INTANG ASSETS - NOX ANNUAL ALLOWANCES - CURRENT
186559	OTH INTANG ASSETS - SO2 ALLOWANCES - FUTURE
186560	CLOSED 06/18 - OTH INTANG ASSETS - NOX OZONE ALLOWANCES - FUTURE
186561	CLOSED 06/18 - OTH INTANG ASSETS - NOX ANNUAL ALLOWANCES - FUTURE
186576	CARROLLTON SALE/LEASEBACK
186700	OTHER DEFERRED LT ASSET - ASU 2017-07 - NON SERVICE COST - PENSION
186701	OTHER DEFERRED LT ASSET - ASU 2017-07 - NON SERVICE COST - OPEB
188001	RESRCH/DEV/DEMO EXP
188901	RESRCH/DEV/DEMO EXP - INDIRECT
189100	UAMORTIZED LOSS ON REACQUIRED DEBT
190007	FASB 109 ADJ-FED
190008	FASB 109 GRS-UP-FED
190009	FASB 109 ADJ-STATE
190010	FASB 109 GRS-UP-ST
190414	DTA ON PROVISIONS FOR PENSIONS - OCI - FED (NON-CURRENT)
190415	DTA FEDERAL - NON-CURRENT
190416	DTA ON FIN 48 - UTP - FEDERAL
190614	DTA ON PROVISIONS FOR PENSIONS - OCI - ST (NON-CURRENT)
190615	DTA STATE - NON-CURRENT
190616	DTA ON FIN 48 - UTP - STATE
201001	COMMON STOCK-AUTH SH
201002	COMMON STOCK-W/O PAR
211001	CONTRIBUTED CAPITAL - MISC.
214010	CAP STOCK EXP-COMMON
216001	UNAPP RETAINED EARN
219010	ACCUM OCI - EQUITY INVEST EEI
219011	ACCUM OCI OF SUBS - PTAX
219013	OCI - FAS 158 INCREASE FUNDED STATUS - GROSS
219014	AOCI - FAS 158 POST-ACQUISITION
219110	DEFERRED TAX - OCI - EQUITY INVEST EEI
219111	ACCUM OCI OF SUBS - TAX
219113	OCI - FAS 158 INCREASE FUNDED STATUS - TAX
219114	AOCI TAX - FAS 158 POST-ACQUISITION
221100	LONG TERM DEBT
221899	CURRENT PORTION OF LONG TERM DEBT
223014	LT NOTES PAYABLE TO SERVCO
223100	LT NOTES PAYABLE TO PPL CAPITAL FUNDING PRINCIPAL
223101	LT - NOTES PAYABLE TO CEP RESERVES
224100	PAA PCB FMV ADJUSTMENT
224200	OTHER LONG-TERM DEBT
226100	DEBT DISCOUNT BONDS
227101	OBLIGATIONS UNDER CAPITAL LEASES - NONCURRENT
227102	OBLIGATIONS UNDER FINANCING LEASES - NONCURRENT
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
228325	FASB 112 - POST EMPLOY MEDICARE SUBSIDY
230011	ASSET RETIREMENT OBLIGATIONS - STEAM - CCR
230012	ASSET RETIREMENT OBLIGATIONS - STEAM
230013	ASSET RETIREMENT OBLIGATIONS - TRANSMISSION
230015	ASSET RETIREMENT OBLIGATIONS - DISTRIBUTION
230016	ASSET RETIREMENT OBLIGATIONS - GAS
230021	ASSET RETIREMENT OBLIGATIONS - STEAM - CCR - ST
230022	ASSET RETIREMENT OBLIGATIONS - STEAM - ST
230026	ASSET RETIREMENT OBLIGATIONS - GAS - ST
230799	RWIP-ARO-ECR
231005	COMMERCIAL PAPER PAYABLE
231006	DISCOUNT ON COMMERCIAL PAPER
231100	CLOSED 06/18 - REVOLVING CREDIT FACILITIES
232001	ACCTS PAYABLE-REG

Oracle Account Setup Details

Account Number	Account Description
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
232027	CREDIT CARD PAYMENTS
232028	AP FUEL - NATURAL GAS
232029	BROWN SOLAR REC LIABILITY
232030	RETAINAGE FEES - NON-ARO
232031	A/P - CWIP ACCRUALS
232032	A/P - RWIP ACCRUALS (NON-ARO)
232033	A/P - RWIP ACCRUALS (ARO)
232034	RETAINAGE FEES - ARO
232042	MISO AND PJM ANCILLARY SERVICES CHARGES A/P
232043	AP REFINED COAL
232060	AP - GAS SUPPLY PURCHASES
232093	SUSPENSE - CCS
232094	SUSPENSE - PPL
232095	SUSPENSE - SALES TAX BURDEN
232096	SUSPENSE - OTHER BURDENS
232097	SUSPENSE - INVENTORY
232099	SUSPENSE ACCOUNT
232100	ACCOUNTS PAYABLE-TRADE
232111	401K LIABILITY - EMPLOYER
232205	IBEW UNION DUES WITHHOLDING PAYABLE
232206	UNITED WAY WITHHOLDING PAYABLE
232211	TIA LIABILITY
232220	CREDIT UNION WITHHOLDING PAYABLE
232233	401K WITHHOLDING PAYABLE
232235	UNITED STEEL WORKERS UNION DUES
232243	LOUISVILLE PAC WITHHOLDING PAYABLE
232244	GARNISHEES WITHHOLDING PAYABLE
232246	DCAP WITHHOLDING PAYABLE
232248	HCRA WITHHOLDING PAYABLE
232249	UNIVERSAL LIFE INS WITHHOLDING PAYABLE
232252	HEALTH EQUITY HIGH DEDUCTIBLE WITHHOLDING PAYABLE
233011	ST - NOTES PAYABLE TO LKE PARENT
233013	ST - NOTES PAYABLE TO SERVCO
233030	N/P TO LKE PARENT - MONEY POOL
233100	N/P TO LG&E - MONEY POOL
233102	N/P TO KU - MONEY POOL
233103	N/P TO LEM - MONEY POOL
234012	I/C PAYABLE CEP RESERVES
234051	INTERCOMPANY PENSION PAYABLE
234052	I/C PAYABLE-PPL SERVICES CORPORATION
234055	I/C PAYABLE-PPL CORPORATION
234056	I/C PAYABLE-PPL CAPITAL FUNDING, INC.
234057	I/C PAYABLE-PPL EU SERVICES CORPORATION
234092	CLOSED 06/18 - I/C PAYABLE TO PPL ENERGY FUNDING CORP
234100	A/P TO ASSOC CO
235001	CUSTOMER DEPOSITS
235002	CUSTOMER DEPOSITS OFF-SYS
235003	CUSTOMER DEPOSITS - TRANSMISSION
236007	FICA-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
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
236036	REAL ESTATE AND PERSONAL PROPERTY TAXES - NON KY

Oracle Account Setup Details

Account Number	Account Description
236037	VIRGINIA USE TAX
236115	STATE UNEMPLOYMENT-OPR
236116	FEDERAL UNEMPLOYMENT-OPR
237100	ACCR INT LONG-TERM DEBT
237300	INT ACC-OTH LIAB
237301	INTEREST ACCRUED ON CUSTOMER DEPOSITS
237304	INTEREST ACCRUED ON TAX LIABILITIES
238200	CLOSED 03/18 - DIV PAYABLE - PARENT FM LGE
238203	CLOSED 03/18 - DIV PAYABLE - PARENT FM KU
238204	CLOSED 03/18 - 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
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
242005	UNEARNED REVENUE - CURRENT
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	CLOSED 06/18 - PENSION PAYABLE - CURRENT
242027	AR CREDITS
242028	SERVICE DEPOSIT REFUND PAYABLE
242030	WINTERCARE ENERGY FUND
242031	NO-NOTICE GAS PAYABLE
242034	MCI UNEARNED REVENUE
242038	COBRA/LTD BENEFITS - PAYABLE
242039	SUSPENSE - CASH
242080	LEASEHOLD INCENTIVE LG&E CENTER LEASE 07012012 - CURRENT
242081	UNEARNED REVENUE - LEASES CURRENT
242101	RETIREMENT INCOME LIABILITY
242102	IBNP MEDICAL AND DENTAL RESERVE
243102	OBLIGATIONS UNDER OPERATING LEASES - CURRENT
243103	OBLIGATIONS UNDER FINANCING LEASES - CURRENT
244511	LT DERIVATIVE LIAB FAS 133 JPM
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
244519	ST DERIV LIAB FAS 133 JPM
252011	LINE EXTENSIONS
252013	CUSTOMER ADVANCES - CONSTRUCTION - LONG TERM
252015	MOBILE HOME LINE
252017	CUSTOMER ADVANCES - SHORT TERM
253004	OTH DEFERRED CR-OTHR
253005	CL ACC FR OTH DEF DR
253025	DEFERRED COMPENSATION
253027	DEFERRED RENT PAYABLE
253031	OTHER LONG TERM OPERATING LIABILITIES
253032	UNCERTAIN TAX POSITION - FEDERAL
253033	UNCERTAIN TAX POSITION - STATE
253034	MCI AMORTIZATION
253037	CLOSED 06/18 - UNEARNED REVENUE - POLE ATTACHMENTS - LONG-TERM
253038	CLOSED 06/18 - OTHER DEF. CREDIT - COAL CONTRACT - ST

Oracle Account Setup Details

Account Number	Account Description
253039	CLOSED 06/18 - OTHER DEF. CREDIT - COAL CONTRACT - LT
253040	LEASEHOLD INCENTIVE LG&E CENTER LEASE 07012012 - LONG TERM
253041	CANE RUN 7 LTPC LIABILITY
253042	LONG TERM RETAINAGE - NON-ARO
253043	LONG TERM RETAINAGE - ARO
253044	BROWN 6 AND 7 LTSA LIABILITY
253050	KY TAX RATE REDUCTION
253301	CLOSED 01/18 - PROVISIONS FOR INDEMNITY OBLIGATIONS
253320	UNCERTAIN TAX POSITIONS - INTEREST
253576	DEF GAIN - CARROLLTON SALE/LEASEBACK
253927	DEFERRED RENT PAYABLE - INDIRECT
254001	FASB 109 ADJ-FED
254002	FASB 109 GR-UP-FED
254003	FASB 109 ADJ-STATE
254004	FASB 109 GR-UP-STATE
254007	REG LIABILITY - GAS SUPPLY CLAUSE
254008	DSM COST RECOVERY
254010	REGULATORY LIABILITY - FAS 158 OPEB
254011	VA FUEL COMPONENT - JURISDICTIONAL CUSTOMERS (CURRENT)
254012	CLOSED 06/18 - SPARE PARTS
254017	ENVIRONMENTAL COST RECOVERY
254018	REGULATORY LIABILITY FAC
254020	GAS LINE TRACKER- REG LIABILITY
254022	REG LIAB - MUNI GEN TRUE UP
254023	VA FUEL COMPONENT - NON-JURISDICTIONAL CUSTOMERS (CURRENT)
254024	REGULATORY LIABILITY - OST
254025	REG LIABILITY - REFINED COAL - KENTUCKY
254026	REG LIABILITY - REFINED COAL - VIRGINIA
254027	REG LIABILITY - REFINED COAL - FERC
254028	REG LIABILITY - TCJA - KPSC ONLY
254029	REG LIABILITY - TCJA - VA ONLY
254030	REG LIAB - ASU 2017-07 - NON SERVICE COST - PENSION
254031	REG LIAB - ASU - 2017-07 - NON SERVICE COST - OPEB
254054	CLOSED 06/18 - 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
254059	REG. LIABILITY - PLANT OUTAGE NORMALIZATION
254090	REGULATORY LIAB FORWARD STARTING SWAPS NOV 2013
254321	MISO EXIT FEE REFUND
254356	CLOSED 06/18 - VA FUEL COMPONENT - JURISDICTIONAL CUSTOMERS (NON-CURRENT)
255004	ITC TC2
255006	JOB DEVELOP CR
255009	ITC SOLAR
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)
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
283514	DTL ON PROVISIONS FOR PENSIONS - OCI - FED (NON-CURRENT)
283515	DTL FEDERAL - NON-CURRENT
283519	DTL ON LIABILITIES - EEI -FED (NON-CURRENT)
283714	DTL ON PROVISIONS FOR PENSIONS - OCI - STATE (NON-CURRENT)
283715	DTL STATE - NON-CURRENT
283719	DTL ON LIABILITIES - EEI - STATE (NON-CURRENT)
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
403016	GENERAL DEPRECIATION EXPENSE
403021	DEPREC. EXP. - UNDERGROUND - GAS
403022	DEPREC. EXP. - TRANSMISSION - GAS
403023	DEPREC. EXP. - DISTRIBUTION - GAS

Oracle Account Setup Details

Account Number	Account Description
403024	DEPREC. EXP. - GENERAL - GAS
403025	DEPREC. EXP. - COMMON
403026	DEPREC. EXP. - STEAM - ECR
403027	DEPREC EXP - ELECTRIC - DSM
403028	DEPREC EXP - GAS - DSM
403029	DEPREC. EXP. - GENERAL - GLT
403030	DEPREC. EXP. - TRANS - GLT
403050	DEPREC EXP FINANCE LEASES
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
403121	DEPREC EXP ARO GAS UNDERGROUND STORAGE
403122	DEPREC EXP ARO GAS DISTRIBUTION
403123	DEPREC EXP ARO GAS TRANSMISSION
403181	DEPRECIATION NEUTRALITY - GENERATION DEPRECIATION
403182	DEPRECIATION NEUTRALITY - TRANSMISSION DEPRECIATION
403185	DEPRECIATION NEUTRALITY - DISTRIBUTION DEPRECIATION
403186	DEPRECIATION NEUTRALITY - GAS DEPRECIATION
403700	DEPREC EXP - CONTRA ASSET - PENSION
403701	DEPREC EXP - CONTRA ASSET - OPEB
404301	AMORT-INTANG GAS PLT
404401	AMT-EL INTAN PLT-RTL
404402	AMT-EL INTAN PLT-WHS
407304	AMORT EXPENSE - OPEN ARO PONDS - KY
407305	AMORT EXPENSE - OPEN ARO PONDS - VA
407306	AMORT EXPENSE - OPEN ARO PONDS - FERC REMAINING MUNI
407307	AMORT EXPENSE - OPEN ARO PONDS - FERC DEPARTING MUNI
407308	AMORT EXPENSE - CLOSED ARO PONDS - KY
407309	AMORT EXPENSE - CLOSED ARO PONDS - VA
407310	AMORT EXPENSE - CLOSED ARO PONDS - FERC REMAINING MUNI
407311	AMORT EXPENSE - CLOSED ARO PONDS - FERC DEPARTING MUNI
407312	AMORT EXPENSE - OPEN ARO PONDS - VA ADJUSTMENT
407313	AMORT EXPENSE - OPEN ARO PONDS - FERC REMAIN ADJUSTMENT
407314	AMORT EXPENSE - OPEN ARO PONDS - FERC DEPART ADJUSTMENT
407315	AMORT EXPENSE - CLOSED ARO PONDS - VA ADJUSTMENT
407316	AMORT EXPENSE - CLOSED ARO PONDS - FERC REMAIN ADJUSTMENT
407317	AMORT EXPENSE - CLOSED ARO PONDS - FERC DEPART ADJUSTMENT
407318	AMORT EXPENSE - CLOSED ARO PONDS - PARIS
407319	AMORT EXPENSE - OPEN ARO PONDS - PARIS
407320	AMORT EXPENSE - CLOSED ARO PONDS - PARIS ADJUSTMENT
407321	AMORT EXPENSE - OPEN ARO PONDS - PARIS ADJUSTMENT
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
408109	REAL AND PERSONAL PROP TAX - GLT DISTR
408110	REAL AND PERSONAL PROP TAX - GLT TRANS
408192	REAL AND PERSONAL PROP. TAX - INDIRECT
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
409108	FED INC TAX - UTIL OPR - SPEC ITEM
409109	KY ST INCOME TAXES - SPEC ITEM
409203	FED INC TAX-OTHER

Oracle Account Setup Details

Account Number	Account Description
409206	ST INC TAX-OTHER
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
409218	FED INC TAX - UTIL OPR - SPEC ITEM-BTL
409219	KY ST INCOME TAXES - SPEC ITEM-BTL
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
410208	DEF FED INC TAX-SPEC ITEM-BTL
410209	DEF ST INC TAX-SPEC ITEM-BTL
411100	ACCRETION EXPENSE - NEUTRALITY
411101	FED INC TX DEF-CR-OP
411102	ST INC TAX DEF-CR-OP
411103	ACCRETION EXPENSE - ELECTRIC
411104	ACCRETION EXPENSE - GAS
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
411201	FD INC TX DEF-CR-OTH
411202	ST INC TX DEF-CR-OTH
411208	FED INC TAX DEF-CR-SPEC ITEM-BTL
411209	ST INC TAX DEF-CR-SPEC ITEM-BTL
411403	ITC DEFERRED
411404	AMORTIZATION OF ITC
411601	GAIN-PLANT HELD FOR FUTURE USE
411701	LOSS-PLANT HELD FOR FUTURE USE
411802	GAIN-DISP OF ALLOW
412001	SERVICE COMPANY CONSTRUCTION OR OTHER SERVICES EXP
412901	SERVICE COMPANY CONSTRUCTION OR OTHER SERVICES EXP - INDIRECT
415001	REVENUE FROM CUSTOMER SERVICE LINES
415004	MERCHANDISE SALES
416004	MERCHANDISE COST OF SALES
417004	SERVICE CHARGE AND SUPERVISORY FEE - IMEA AND IMPA
417005	IMPA-WORKING CAPITAL
417006	IMEA-WORKING CAPITAL
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)
417199	OPERATING EXPENSES OF NON-UTILITY OPERATIONS
418001	NONOPR RENT INCOME

Oracle Account Setup Details

Account Number	Account Description
418110	EQUITY IN EARNINGS OF CONSOLIDATED SUBSIDIARIES
419002	INT INC-US TREAS SEC
419005	INT INC-FED TAX PMT
419006	INT INC-ST TAX PMT
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
420003	AMORTIZATION OF ITC
421001	MISC NONOPR INCOME - INDIRECT
421003	KM LIFE INS - CASH SURRENDER VALUE
421006	AOCI ADJUSTMENT OF SUBSIDIARY - EEI
421007	MISC NONOPR INCOME - DIRECT
421101	GAIN-PROPERTY DISP
421105	GAIN ON ARO SETTLEMENT
421106	GAIN - LEASE DISP
421201	LOSS-PROPERTY DISP
421206	LOSS - LEASE DISP
421301	PRETAX GAIN/LOSS ON DISPOSAL OF DISC OPERS
421306	PRETAX GAIN/LOSS ON DISPOSAL OF DISC OPERS - CENTURY RECEIVABLE
426101	DONATIONS
426120	SPONSORSHIP/OTHER COMMUNITY RELATIONS
426190	SPONSORSHIP/OTHER COMMUNITY RELATIONS - INDIRECT
426191	DONATIONS - INDIRECT
426201	LIFE INSURANCE
426301	PENALTIES
426391	PENALTIES - INDIRECT
426401	EXP-CIVIC/POL/REL
426491	EXP-CIVIC/POL/REL - INDIRECT
426501	OTHER DEDUCTIONS
426502	CLOSED 06/18 - SERP
426504	CLOSED 06/18 - OFFICERS TIA
426505	CLOSED 06/18 - OFFICER LONG-TERM INCENT
426513	OTHER OFFICER BENEFITS
426591	OTHER DEDUCTIONS - INDIRECT
427100	INTEREST EXPENSE
428090	OTHER AMORT OR DEBT DISCOUNT AND EXP
428190	OTHER AMORT-REACQ DEBT
428200	AM DISC-LONG TERM DEBT
430002	INT-DEBT TO ASSOC CO
430004	I/C INT EXP CEP RESERVES
430100	I/C INT EXP DEBT WITH PPL CAPITAL FUNDING
430101	I/C INTEREST EXPENSE - LT-NOTES CEP RESERVES
431002	INT-CUST DEPOSITS
431003	INT-FED TAX DEFNCY
431004	INT-OTHER TAX DEFNCY
431008	INT-DSM COST RECOVER
431014	INTEREST ON CUSTOMER REFUNDS
431015	INTEREST ON RATES REFUND-RETAIL
431016	INTEREST ON REFUNDS - MUNICIPALS
431017	UTP INTEREST - FED INC TAX
431018	UTP INTEREST - STATE INC TAX
431104	INTEREST EXPENSE FROM FINANCIAL LIABILITIES
431106	INTEREST ON PROPERTY UNDER FINANCING LEASES
431200	INTEREST EXP SHORT-TERM DEBT- CP
432001	ALLOW FOR FUNDS USED DURING CONSTRUC-BORROWED
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
438003	COMMON STK DIVS DECL - LEL
438005	COMMON STK DIVS DECL - PARENT FM KU
438006	COMMON STOCK DIV DECLARED PPL FM LKE

Oracle Account Setup Details

Account Number	Account Description
439002	RETAINED EARNINGS ADJ
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	CLOSED 02/18 - ELECTRIC RESIDENTIAL MSR
440113	ELECTRIC RESIDENTIAL OSS TRACKER (ESM)
440115	ELECTRIC RESIDENTIAL TCJA SURCREDIT
440116	ELECTRIC RESIDENTIAL DEMAND ECR
440117	ELECTRIC RESIDENTIAL ENERGY ECR
440118	ELECTRIC RESIDENTIAL DEMAND CHG REV
440119	ELECTRIC RESIDENTIAL CUST CHG REV
440121	ELECTRIC RESIDENTIAL SOLAR CAPACITY CHG
440122	ELECTRIC RESIDENTIAL SOLAR ENERGY CREDIT
440123	ELECTRIC RESIDENTIAL SOLAR FAC OFFSET
440124	ELECTRIC RESIDENTIAL SOLAR OST OFFSET
440126	ELECTRIC RESIDENTIAL SOLAR ENERGY FUEL CREDIT
442020	LG COMMERC SALES-EL - KWH - (STAT ONLY)
442021	LG COMMERC SALES-EL - CUS - (STAT ONLY)
442025	KU COMMERCIAL SALES - KWH - (STAT ONLY)
442026	KU COMMERCIAL SALES - CUS - (STAT ONLY)
442030	LG INDUSTR SALES-El-OTHER - KWH - (STAT ONLY)
442031	LG INDUSTR SALES-EL-OTHER - CUS - (STAT ONLY)
442035	KU INDUSTRIAL SALES - KWH - (STAT ONLY)
442036	KU INDUSTRIAL SALES - CUS - (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
442111	ELECTRIC SMALL COMMERCIAL ECR
442113	ELECTRIC SMALL COMMERCIAL OSS TRACKER (ESM)
442115	ELECTRIC SMALL COMMERCIAL TCJA SURCREDIT
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
442211	ELECTRIC LARGE COMMERCIAL ECR
442213	ELECTRIC LARGE COMMERCIAL OSS TRACKER (ESM)
442215	ELECTRIC LARGE COMMERCIAL TCJA SURCREDIT
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
442221	ELECTRIC LARGE COMMERCIAL SOLAR CAPACITY CHG
442222	ELECTRIC LARGE COMMERCIAL SOLAR ENERGY CREDIT
442223	ELECTRIC LARGE COMMERCIAL SOLAR FAC OFFSET
442224	ELECTRIC LARGE COMMERCIAL SOLAR OST OFFSET
442225	ELECTRIC LARGE COMMERCIAL DEMAND EDR
442226	ELECTRIC LARGE COMMERCIAL SOLAR ENERGY FUEL CREDIT
442301	ELECTRIC INDUSTRIAL DSM
442302	ELECTRIC INDUSTRIAL ENERGY NON-FUEL REV
442303	ELECTRIC INDUSTRIAL ENERGY FUEL REV
442304	ELECTRIC INDUSTRIAL FAC
442311	ELECTRIC INDUSTRIAL ECR
442313	ELECTRIC INDUSTRIAL OSS TRACKER (ESM)
442315	ELECTRIC INDUSTRIAL TCJA SURCREDIT
442316	ELECTRIC INDUSTRIAL DEMAND ECR
442317	ELECTRIC INDUSTRIAL ENERGY ECR
442318	ELECTRIC INDUSTRIAL DEMAND CHG REV
442319	ELECTRIC INDUSTRIAL CUST CHG REV

Oracle Account Setup Details

Account Number	Account Description
442321	ELECTRIC INDUSTRIAL SOLAR CAPACITY CHG
442322	ELECTRIC INDUSTRIAL SOLAR ENERGY CREDIT
442323	ELECTRIC INDUSTRIAL SOLAR FAC OFFSET
442324	ELECTRIC INDUSTRIAL SOLAR OST OFFSET
442325	ELECTRIC INDUSTRIAL DEMAND EDR
442326	ELECTRIC INDUSTRIAL SOLAR ENERGY FUEL CREDIT
442601	MINE POWER DSM
442602	MINE POWER ENERGY NON-FUEL REV
442603	MINE POWER ENERGY FUEL REV
442604	MINE POWER FAC
442611	MINE POWER ECR
442613	MINE POWER OSS TRACKER (ESM)
442615	MINE POWER TCJA SURCREDIT
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)
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
444111	ELECTRIC STREET LIGHTING ECR
444113	ELECTRIC STREET LIGHTING OSS TRACKER (ESM)
444115	ELECTRIC STREET LIGHTING TCJA SURCREDIT
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)
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
445111	ELECTRIC PUBLIC AUTH ECR
445113	ELECTRIC PUBLIC AUTH OSS TRACKER (ESM)
445115	ELECTRIC PUBLIC AUTH TCJA SURCREDIT
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
445121	ELECTRIC PUBLIC AUTH SOLAR CAPACITY CHG
445122	ELECTRIC PUBLIC AUTH SOLAR ENERGY CREDIT
445123	ELECTRIC PUBLIC AUTH SOLAR FAC OFFSET
445124	ELECTRIC PUBLIC AUTH SOLAR OST OFFSET
445125	ELECTRIC PUBLIC AUTH DEMAND EDR
445126	ELECTRIC PUBLIC AUTH SOLAR ENERGY FUEL CREDIT
445301	MUNI PUMPING DSM
445302	MUNI PUMPING ENERGY NON-FUEL REV
445303	MUNI PUMPING ENERGY FUEL REV
445304	MUNI PUMPING FAC
445311	MUNI PUMPING ECR
445313	MUNI PUMPING OSS TRACKER (ESM)
445315	MUNI PUMPING TCJA SURCREDIT
445316	MUNI PUMPING DEMAND ECR
445317	MUNI PUMPING ENERGY ECR
445318	MUNI PUMPING DEMAND CHG REV
445319	MUNI PUMPING CUST CHG REV
447005	I/C SALES - OSS
447006	I/C SALES NL
447011	FIRM SALES - ENERGY-OTHER - CUS - (STAT ONLY)
447021	FIRM SALES - MUNI/BEREA - KWH - (STAT ONLY)
447022	FIRM SALES - MUNI/BEREA - CUS
447049	SPOT SALES - ENERGY
447050	OFF-SYSTEM SALES REVENUE TO THIRD PARTIES
447302	RESALE MUNICIPALS BASE REV
447303	RESALE MUNICIPALS BASE REV FUEL

Oracle Account Setup Details

Account Number	Account Description
447304	RESALE MUNICIPALS FAC
447318	RESALE MUNICIPALS DEMAND CHG REV
447319	RESALE MUNICIPALS CUST CHG REV
447402	ELEC WLSE SPECIAL CONTRACT - NON-FUEL REV
447403	ELEC WLSE SPECIAL CONTRACT - FUEL REV
447418	ELEC WLSE SPECIAL CONTRACT - DEMAND CHG REV
447419	ELEC WLSE SPECIAL CONTRACT - 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
451005	UNAUTHORIZED RECONNECT (UAR)
454001	CATV ATTACH RENT
454002	OTH RENT-ELEC PROP
454003	RENT FRM FIBER OPTIC
454006	FACILITY CHARGES
454007	ELECTRIC VEHICLE CHARGING STATION RENTAL
454008	REFINED COAL LICENSE FEE
454009	RENT ELECTRIC PROPERTY - LEASE
454900	I/C JOINT USE RENT REVENUE-ELEC-INDIRECT
454901	I/C JOINT USE RENT REVENUE-ELEC-INDIRECT (PPL ELIM)
456003	COMP-TAX REMIT-ELEC
456004	COMP-STBY PWR-H2O CO
456007	RET CHECK CHRG-ELEC
456008	OTHER MISC ELEC REVS
456018	COAL RESALE REVENUES - REFINED COAL
456022	INDUSTRIAL COAL SERVICES INCOME
456023	COAL RESALE EXPENSES - REFINED COAL
456024	INDUSTRIAL COAL SERVICES EXPENSE
456028	EXCESS FACILITIES CHARGES/NRB ELECTRIC REV (ENDED 04/09)
456029	CLOSED 06/18 - GYPSUM REVENUES
456030	FORFEITED REFUNDABLE ADVANCES
456031	SSP - SUBSCRIPTION FEES
456090	REVENUE FROM RENEWABLE ENERGY CREDITS
456099	POWER DELIVERED TO GOVERNMENT (STAT ONLY)
456109	NL TRANSMISSION OF ELECTRIC ENERGY-3RD PARTY
456110	ELEC WLSE SPECIAL CONTRACT - TRANSMISSION
456130	THIRD PARTY ENERGY NATIVE LOAD TRANSMISSION
456131	THIRD PARTY SCHEDULE 1 NATIVE LOAD TRANSMISSION
456132	THIRD PARTY SCHEDULE 2 NATIVE LOAD TRANSMISSION
456133	THIRD PARTY SCHEDULE 3 NATIVE LOAD TRANSMISSON
456134	THIRD PARTY DEMAND NATIVE LOAD TRANSMISSION
456135	THIRD PARTY SCHEDULE 5 NATIVE LOAD TRANSMISSION
456136	THIRD PARTY SCHEDULE 6 NATIVE LOAD TRANSMISSION
456140	INTERCOMPANY NATIVE LOAD ENERGY TRANSMISSION
456141	INTERCOMPANY NATIVE LOAD SCH 1 TRANSMISSION
456142	INTERCOMPANY NATIVE LOAD SCH 2 TRANSMISSION
456143	INTERCOMPANY NATIVE LOAD DEMAND TRANSMISSION
456150	INTERCOMPANY RETAIL SOURCE ENERGY TRANSMISSION
456151	INTERCOMPANY RETAIL SOURCE SCH 1 TRANSMISSION
456152	INTERCOMPANY RETAIL SOURCE SCH 2 TRANSMISSION
456153	INTERCOMPANY RETAIL SOURCE DEMAND TRANSMISSION
456160	INTRACOMPANY NATIVE LOAD ENERGY TRANSMISSION
456161	INTRACOMPANY NATIVE LOAD SCH 1 TRANSMISSION
456162	INTRACOMPANY NATIVE LOAD SCH 2 TRANSMISSION
456163	INTRACOMPANY NATIVE LOAD DEMAND TRANSMISSION
456170	INTRACOMPANY RETAIL SOURCE ENERGY TRANSMISSION
456171	INTRACOMPANY RETAIL SOURCE SCH 1 TRANSMISSION
456172	INTRACOMPANY RETAIL SOURCE SCH 2 TRANSMISSION
456173	INTRACOMPANY RETAIL SOURCE DEMAND TRANSMISSION
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)

Oracle Account Setup Details

Account Number	Account Description
480011	RESID VARIABLE(FUEL) - CUS - (STAT ONLY)
480101	GAS RESIDENTIAL DSM
480102	GAS RESIDENTIAL ENERGY REV
480104	GAS RESIDENTIAL GSC
480106	GAS RESIDENTIAL GLT DISTR
480107	GAS RESIDENTIAL WNA
480108	GAS RESIDENTIAL GLT TRANS
480115	GAS RESIDENTIAL TCJA SURCREDIT
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
481102	GAS COMMERCIAL ENERGY REV
481104	GAS COMMERCIAL GSC
481105	GAS COMMERCIAL CASHOUT
481106	GAS COMMERICAL GLT DISTR
481107	GAS COMMERCIAL WNA
481108	GAS COMMERCIAL GLT TRANS
481115	GAS COMMERCIAL TCJA SURCREDIT
481119	GAS COMMERCIAL CUST CHG REV
481201	GAS INDUSTRIAL DSM
481202	GAS INDUSTRIAL ENERGY REV
481204	GAS INDUSTRIAL GSC
481205	GAS INDUSTRIAL CASHOUT
481206	GAS INDUSTRIAL GLT DISTR
481208	GAS INDUSTRIAL GLT TRANS
481215	GAS INDUSTRIAL TCJA SURCREDIT
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
482106	GAS PUBLIC AUTH GLT DISTR
482107	GAS PUBLIC AUTH WNA
482108	GAS PUBLIC AUTH GLT TRANS
482115	GAS PUBLIC AUTH TCJA SURCREDIT
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
484105	PADDYS RUN CASHOUT - INTRACOMPANY
484106	GAS INTERDEPARTMENTAL GLT DISTR
484108	GAS INTERDEPARTMENTAL GLT TRANS
484115	GAS INTERDEPARTMENTAL TCJA SURCREDIT
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
488006	UNAUTHORIZED RECONNECT (UAR) - GAS
489201	GAS TRANSPORT INTERDEPARTMENTAL - BASE
489204	GAS TRANSPORT INTERDEP - CASHOUT OFO/UCDI
489215	GAS TRANSPORT - INTERDEPARTMENTAL
489301	GAS TRANSPORT - DSM
489302	GAS TRANSPORT - INDUSTRIAL
489304	GAS TRANSPORT - CASHOUT OFO/UCDI
489306	GAS TRANSPORT - GLT-DISTRIBUTION
489308	GAS TRANSPORT - GLT-TRANSMISSION
489310	GAS TRANSPORT - CUSTOMERS (STAT ONLY)
489312	GAS TRANSPORT - DIRECT PAY - STATS ONLY
489315	GAS TRANSPORT - TCJA SURCREDIT
489319	TRANSPORT GAS - CUSTOMER CHARGE

Oracle Account Setup Details

Account Number	Account Description
489322	GAS TRANSPORT - COMMERCIAL
489332	GAS TRANSPORT - PUBLIC AUTHORITY
493001	RENT-GAS PROPERTY
493002	RENT GAS PROPERTY - LEASE
493900	I/C JOINT USE RENT REVENUE-GAS-INDIRECT
493901	I/C JOINT USE RENT REVENUE FROM PPL-GAS-INDIRECT
495002	COMP-TAX REMIT-GAS
495005	RET CHECK CHRG-GAS
495006	OTHER GAS REVENUES
500100	OPER SUPER/ENG
500900	OPER SUPER/ENG - INDIRECT
501001	FUEL-COAL - TON
501002	FUEL-COAL - BTU - (STAT ONLY)
501003	CLOSED 06/18 - COAL ADDITIVES
501004	FUEL COAL - TO SOURCE UTILITY OSS
501005	FUEL COAL - OSS
501006	FUEL COAL - OFFSET
501007	FUEL COAL - TO SOURCE UTILITY RETAIL
501009	OSS INCREMENTAL COAL EXPENSE
501019	REFINED COAL - COAL YARD SERVICES
501020	START-UP OIL -GAL
501021	START-UP OIL - BTU - (STAT ONLY)
501022	STABILIZATION OIL - GAL
501023	STABILIZATION OIL - BTU - (STAT ONLY)
501027	AMORTIZATION OF REFINED COAL - COAL YARD SERVICES - KY
501090	FUEL HANDLING
501091	FUEL SAMPLING AND TESTING
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)
501200	BOTTOM ASH DISPOSAL
501202	CLOSED 06/18 - BOTTOM ASH PROCEEDS
501250	FLY ASH PROCEEDS
501251	CLOSED 06/18 - FLY ASH DISPOSAL
501253	ECR FLY ASH DISPOSAL
501990	FUEL HANDLING - INDIRECT
502001	OTHER WASTE DISPOSAL
502002	BOILER SYSTEMS OPR
502003	SDRS OPERATION
502004	SDRS-H2O SYS OPR
502005	CLOSED 06/18 - SLUDGE STAB SYS OPR
502006	SCRUBBER REACTANT EX
502011	ECR OTHER WASTE DISPOSAL
502012	LANDFILL OPERATION
502013	ECR LANDFILL OPERATIONS
502014	PROCESS WATER CHEMICALS
502022	CLOSED 06/18 - OTHER WASTE DISPOSAL - OSS
502023	CLOSED 06/18 - OTHER WASTE DISPOSAL - OFFSET
502025	REACTANT - EXTERNAL OSS
502026	SCRUBBER REACTANT - OFFSET
502027	SCRUBBER REACTANT - TO SOURCE UTILITY OSS
502056	CLOSED 06/18 - ECR SCRUBBER REACTANT EX
502057	CLOSED 06/18 - ECR SCRUBBER REACTANT OSS OFFSET
502058	CLOSED 06/18 - ECR SCRUBBER REACTANT EX - OSS
502100	STM EXP(EX SDRS.SPP)
502900	STM EXP(EX SDRS.SPP) - INDIRECT
504001	CLOSED 06/18 - 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
506104	NOX REDUCTION REAGENT
506105	OPERATION OF SCR/NOX REDUCTION EQUIP
506107	AMMONIA - EXTERNAL OSS
506108	SCR/NOX - OFFSET
506109	SORBENT INJECTION OPERATION

Oracle Account Setup Details

Account Number	Account Description
506110	MERCURY MONITORS OPERATIONS
506111	ACTIVATED CARBON
506112	SORBENT REACTANT - REAGENT ONLY
506113	LIQUID INJECTION - REAGENT ONLY
506114	AMMONIA - TO SOURCE UTILITY OSS
506150	ECR MERCURY MONITORS OPERATIONS
506151	ECR ACTIVATED CARBON
506152	ECR SORBENT REACTANT - REAGENT ONLY
506153	ECR LIQUID INJECTION - REAGENT ONLY
506154	ECR NOX REDUCTION REAGENT
506156	ECR BAGHOUSE OPERATIONS
506159	ECR SORBENT INJECTION OPERATION
506160	ECR OTHER STEAM EXPENSE OSS OFFSET
506161	ECR ACTIVATED CARBON - OSS
506162	ECR SORBENT REACTANT - REAGENT ONLY - OSS
506163	ECR NOX REDUCTION REAGENT - OSS
506164	ECR LIQUID INJECTION - REAGENT ONLY - OSS
506900	MISC STM PWR EXP - INDIRECT
507100	RENTS-STEAM
509002	SO2 EMISSION ALLOWANCES
509003	NOX EMISSION ALLOWANCES
509007	CLOSED 06/18 - EMISSION ALLOWANCES - EXTERNAL OSS
509008	CLOSED 06/18 - EMISSION ALLOWANCES - OFFSET
509009	CLOSED 06/18 - EMISSION ALLOWANCES - TO SOURCE UTILITY OSS
509052	ECR SO2 EMISSION ALLOWANCES
509053	ECR NOX EMISSION ALLOWANCES
510100	MTCE SUPER/ENG - STEAM
510900	MTCE SUPER/ENG - STEAM - INDIRECT
511100	MTCE-STRUCTURES
512005	MAINTENANCE-SDRS
512011	INSTR/CNTRL-ENVRNL
512015	SDRS-COMMON H2O SYS
512016	MAINTENANCE - MERC CONTROL
512017	MTCE-SLUDGE STAB SYS
512055	ECR MAINTENANCE-SDRS
512056	ECR MAINTENANCE - MERC CONTROL
512100	MTCE-BOILER PLANT
512101	MAINTENANCE OF SCR/NOX REDUCTION EQUIP
512102	SORBENT INJECTION MAINTENANCE
512103	MERCURY MONITORS MAINTENANCE
512107	ECR LANDFILL MAINTENANCE
512108	ECR CCR BEN REUSE SYSTEM MAINT
512151	ECR MAINTENANCE OF SCR/NOX REDUCTION EQUIP
512152	ECR SORBENT INJECTION 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
546900	OPER SUPER/ENG - TURBINES - INDIRECT
547010	KWH GEN-OTH PWR-OIL - (STAT ONLY)
547020	KWH GEN-OTH PWR-GAS - (STAT ONLY)
547021	KWH GEN-OTH PWR-SOLAR - (STAT ONLY)
547030	FUEL-GAS - MCF
547031	FUEL-GAS - BTU - (STAT ONLY)
547040	FUEL-OIL - GAL
547041	FUEL-OIL - BTU - (STAT ONLY)

Oracle Account Setup Details

Account Number	Account Description
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)
547058	OSS INCREMENTAL CT EXPENSE
548010	GENERATION EXP
548910	GENERATION EXP - INDIRECT
549001	SO2 EMISSION ALLOWANCES
549002	AIR QUALITY EXPENSES
549003	NOX EMISSION ALLOWANCES
549100	MISC OTH PWR GEN EXP
549900	MISC OTH PWR GEN EXP - INDIRECT
550100	RENTS-OTH PWR
551100	MTCE-SUPER/ENG - TURBINES
551900	MTCE-SUPER/ENG - TURBINES - INDIRECT
552100	MTCE-STRUCTURES - OTH PWR
553010	MTCE-GEN/ELECT EQ
553200	MTCE-HEAT RECOVERY STM GEN
553910	MTCE-GEN/ELECT EQ - INDIRECT
554100	MTCE-MISC OTH PWR GEN
555010	OSS POWER PURCHASES
555011	MONTHLY FUEL ADJUSTMENT (MFA) RELATED CAPACITY/TOLLING PURCHASE POWER
555015	NL POWER PURCHASES - ENERGY
555016	NL POWER PURCHASES - DEMAND
555017	DEMAND FOR TOLLING/CAPACITY AGREEMENTS
555020	OSS I/C POWER PURCHASES
555025	NL I/C POWER PURCHASES
555080	PURCHASE POWER NATIVE LOAD - SQF AND LQF TARIFF
555101	INAD INTER REC-KWH - (STAT ONLY)
555110	INAD INTER DEL-KWH - (STAT ONLY)
556100	SYS CTRL / DISPATCHING
556900	SYS CTRL / DISPATCHING - INDIRECT
557100	CLOSED 06/18 - OTH POWER SUPPLY EXP
557111	MARKET FEES - OFF SYSTEM SALES
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
557920	ADMIN FEES FOR RESERVE SHARING AGREEMENT - INDIRECT
560100	OP SUPER/ENG-SSTOPER
560900	OP SUPER/ENG-SSTOPER - INDIRECT
561100	CLOSED 06/18 - LOAD DISPATCH-WELOB
561190	LOAD DISPATCH - INDIRECT
561201	LOAD DISPATCH-MONITOR AND OPERATE TRANSMISSION SYSTEM
561291	LOAD DISPATCH-MONITOR AND OPERATE TRANSMISSION SYSTEM - INDIRECT
561391	LOAD DISPATCH-TRANSMISSION SERVICE AND SCHEDULING - INDIRECT
561590	RELIABILITY, PLANNING AND STANDARDS DEVELOPMENT - INDIRECT
561601	TRANSMISSION SERVICE STUDIES
561701	GENERATION INTERCONNECTION STUDIES
562010	STA EXP-SUBST OPER
562090	STA EXP - SUBST OPER - I
563100	OTHER INSP-ELEC TRAN
565002	TRANSMISSION ELECTRIC OSS
565005	TRANSMISSION ELECTRIC NATIVE LOAD
565014	INTERCOMPANY TRANSMISSION EXPENSE
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
566151	TRANSMISSION DEPANCAKING EXPENSES
566900	MISC TRANS EXP-SSTMT - INDIRECT

Oracle Account Setup Details

Account Number	Account Description
566940	INDEPENDENT OPERATOR - INDIRECT
567100	RENTS-ELEC/SUBSTATION OPERATIONS
567900	I/C JOINT USE RENT EXPENSE-TRANS-INDIRECT
569100	CLOSED 06/18 - MTCE-STRUCT-SSTMTCE
570010	MTCE-ST EQ-SSTMTCE
570900	MTCE-ST EQ-SSTMTCE - INDIRECT
571100	MTCE OF OVERHEAD LINES
573100	MTCE-MISC TR PLT-SSTMT
573900	MTCE-MISC TR PLT-SSTMT INDIRECT
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
575708	NL MISO D1 SCHEDULE 10 - MKT ADMIN
580100	OP SUPER/ENG-SSTOPER
580900	OP SUPER/ENG-SSTOPER - INDIRECT
581100	SYS CTRL/SWITCH-DIST
581900	SYS CTRL/SWITCH-DIST - INDIRECT
582100	STATION EXP-SSTOPER
583001	OPR-O/H LINES
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
584002	INSPC U/G LINE FACIL
584003	LOAD/VOLT TEST-U/G
584005	CLOSED 06/18 - RESP-U/G CUST COMPL
584008	INST/RMV/REPL TRANSF
585100	CLOSED 06/18 - 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
593904	TREE TRIMMING - INDIRECT
594001	MTCE-ELEC MANHOL ETC
594002	MTCE-U/G COND ETC
595100	MTCE-TRANSF/REG
596100	MTCE OF STREET LIGHTING AND SIGNALS
597100	CLOSED 06/18 - MAINTENANCE OF METERS
598100	MTCE OF MISC DISTRIBUTION PLANT
598900	MTCE OF MISC DISTRIBUTION PLANT - INDIRECT
803001	GAS TRANS LINE PURCH
803002	CLOSED 06/18 - PURCHASED GAS REFUND
803003	GAS COST ACTUAL ADJ
803004	GAS COST BALANCE ADJ
803006	PURCHASED GAS - WHOLESALE SALES
803007	GAS OSS INCENTIVE
803008	ACQ AND TRANS INCENTIVE
803009	PBR RECOVERY
803010	END USERS GAS PURCHASE (MCF ONLY) - (STAT ONLY)
806001	EXCHANGE GAS - INJECTIONS
806002	EXCHANGE GAS - WITHDRAWALS
807401	CLOSED 06/18 - PURCH GAS CALC EXP
807501	CLOSED 06/18 - OTHER PURCH GAS EXP
807502	GAS PROCUREMENT EXP

Oracle Account Setup Details

Account Number	Account Description
808101	GAS W/D FROM STOR-DR
808201	GAS DELD 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
813001	CLOSED 06/18 - OTH GAS SUPPLY EXP
813003	LOST AND UNACCOUNTED FOR GAS - TRANSPORTS (STAT ONLY)
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	CLOSED 06/18 - 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
851100	SYS CTRL/DSPTCH-GAS
852100	CLOSED 06/18 - OPR-COM EQ-GAS TRANS
856100	MAINS EXPENSES
859100	OTH GAS TRANS EXP
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
874110	GLT - OTHER MAINS / SERV EXP.
875100	MEAS/REG STA-GENERAL
876100	MEAS/REG STA-INDUSTRIAL
877100	MEAS/REG STA-CITY GATE
878100	METER/REG EXPENSE
878110	GLT - METER/REG EXP.
879100	CUST INSTALL EXPENSE
879110	GLT-CUSTOMER INSTALL
880016	GAS LOST / UNACCT FOR (MCF) - (STAT ONLY)
880100	OTH GAS DISTR EXPENSE
880110	GAS RISER AND LEAK MITIGATION TRACKER EXPENSES - BUDGET ONLY
880900	OTH GAS DISTR EXPENSE - INDIRECT
881100	RENTS-GAS DISTR
886100	CLOSED 06/18 - MTCE-GAS DIST STRUCT
887100	MTCE-GAS MAINS-DISTR
887110	GLT- MTCE GAS MAINS DIST.
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
892110	GLT-MTCE-OTHER SERVICE
892900	MTCE-OTH SERVICES - INDIRECT
893100	CLOSED 06/18 - MTCE-METER/HOUSE REG
894100	MTCE-OTHER EQUIP
894900	MTCE-OTHER EQUIP - INDIRECT
901001	SUPV-CUST ACCTS
901900	SUPV-CUST ACCTS - INDIRECT
902001	METER READ-SERV AREA

Oracle Account Setup Details

Account Number	Account Description
902002	METER READ-CLER/OTH
902900	METER READ-SERV AREA - INDIRECT
903001	CLOSED 06/18 - AUDIT CUST ACCTS
903002	CLOSED 06/18 - 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	CLOSED 06/18 - HANDLE CREDIT PROBS
903022	COLL OFF-LINE BILLS
903023	PROC BANKRUPT CLAIMS
903025	MTCE-ASST PROGRAMS
903030	PROC CUST REQUESTS
903031	CLOSED 06/18 - PROC CUST PAYMENTS
903032	DELIVER BILLS-REG
903035	COLLECTING-OTHER
903036	CUSTOMER COMPLAINTS
903038	MISC CASH OVERAGE/SHORTAGE
903901	AUDIT CUST ACCTS - INDIRECT
903902	BILL SPECIAL ACCTS - INDIRECT
903903	PROCESS METER ORDERS - INDIRECT
903906	CUST BILL/ACCTG - INDIRECT
903907	PROCESS PAYMENTS - INDIRECT
903908	INVESTIGATE THEFT OF SERVICE - INDIRECT
903909	PROC EXCEPTION PMTS - INDIRECT
903912	PROC CUST CNTRT/ORDR - INDIRECT
903922	COLLECT OFF-LINE BILLS - INDIRECT
903930	PROC CUST REQUESTS - INDIRECT
903931	PROC CUST PAYMENTS - INDIRECT
903935	COLLECTING-OTHER - INDIRECT
903936	CUSTOMER COMPLAINTS - INDIRECT
904001	UNCOLLECTIBLE ACCTS
904003	UNCOLL ACCTS - A/R MISC
904005	UNCOLLECTIBLE ACCTS - GSC
905001	MISC CUST SERV EXP
905002	CLOSED 06/18 - MISC CUST BILL/ACCTG
905003	MISC COLLECTING EXP
905900	MISC CUST SERV EXP - INDIRECT
907001	SUPV-CUST SER/INFO
907900	SUPV-CUST SER/INFO - INDIRECT
908004	DSM - ENERGY AUDIT
908005	DSM CONSERVATION PROG
908006	DSM - HVAC
908007	DSM - CONSERVATION
908009	MISC MARKETING EXP
908011	DSM CONSERVATION PROGRAM - GAS EXPENSE RECLASS
908901	CUST MKTG/ASSIST - INDIRECT
908902	CLOSED 06/18 - RES CONS/ENG ED PROG - INDIRECT
908909	MISC MARKETING EXP - INDIRECT
909004	CLOSED 06/18 - MISC CUST COM-SER/IN
909005	MEDIA RELATIONS
909010	PRINT ADVER-SER/INFO
909011	OTH ADVER-SER/INFO
909013	SAFETY PROGRAMS
909910	PRINT ADVER-SER/INFO - INDIRECT
909911	OTHER ADVER-SER/INFO - INDIRECT
910001	MISC CUST SER/INFO
910900	MISC CUST SER/INFO - INDIRECT
912003	CLOSED 06/18 - GEN MKTG AND MKTG PGMS
913012	OTH ADVER-SALES
913912	OTH ADVER-SALES - INDIRECT
920100	OTHER GENERAL AND ADMIN SALARIES
920900	OTHER GENERAL AND ADMIN SALARIES - INDIRECT
920902	AMS REGULATORY ASSET SALARIES - INDIRECT
921002	EXP-GEN OFFICE EMPL
921003	GEN OFFICE SUPPL/EXP

Oracle Account Setup Details

Account Number	Account Description
921004	OPR-GEN OFFICE BLDG
921902	INDIRECT EMPLOYEE OFFICE EXPENSE ALLOCATION
921903	GEN OFFICE SUPPL/EXP - INDIRECT
921904	I/C OPR-GEN OFFICE BLDG - INDIRECT
921905	OFC EQUIP DEPR COST OF SALES OFFSET-INDIRECT (LKS ONLY)
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
923301	OUTSIDE SERVICES - AUDIT FEES - OTHER
923900	OUTSIDE SERVICES - INDIRECT
924100	PROPERTY INSURANCE
924900	PROPERTY INSURANCE - INDIRECT
925001	PUBLIC LIABILITY
925002	WORKERS COMP EXPENSE - BURDENS
925003	AUTO LIABILITY
925004	SAFETY AND INDUSTRIAL HEALTH
925100	OTHER INJURIES AND DAMAGES
925900	OTHER INURIES AND DAMAGES - INDIRECT
925902	WORKERS COMP EXPENSE - BURDENS INDIRECT
925904	CLOSED 06/18 - 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	PENSION SERVICE COST - BURDENS
926102	401K EXPENSE - BURDENS
926105	FASB 112 POST EMPLOYMENT EXPENSE - BURDENS
926106	FASB 106 (OPEB) SERVICE COST - BURDENS
926110	EMPLOYEE WELFARE
926112	CLOSED 05/18 - PENSION EXP- VA
926113	CLOSED 05/18 - PENSION EXP- FERC AND TENN.
926116	RETIREMENT INCOME EXPENSE - BURDENS
926117	CLOSED 05/18 - PENSION NON SERVICE COST - BURDENS
926118	CLOSED 05/18 - FASB 106 POST RETIREMENT NON SERVICE COST EXPENSE - BURDENS
926194	PENSION NON SERVICE COST - BURDENS - LKS (19)
926195	FASB 106 POST RETIREMENT NON SERVICE COST EXPENSE - BURDENS - LKS (19)
926196	PENSION EXP- VA
926197	PENSION EXP- FERC AND TENN.
926198	PENSION NON SERVICE COST - BURDENS
926199	FASB 106 POST RETIREMENT NON SERVICE COST EXPENSE - BURDENS
926900	EMPLOYEE BENEFITS - NON-BURDEN - INDIRECT
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
926906	PENSION EXP- VA - INDIRECT
926907	PENSION EXP- FERC AND TENN. - INDIRECT
926910	EMPLOYEE WELFARE - INDIRECT
926911	PENSION SERVICE COST - BURDENS INDIRECT
926912	401K EXPENSE - BURDENS INDIRECT
926915	FASB 112 POST EMPLOYMENT EXPENSE - BURDENS INDIRECT
926916	FASB 106 (OPEB) SERVICE COST - BURDENS INDIRECT
926917	CLOSED 05/18 - PENSION NON SERVICE COSTS - BURDENS INDIRECT
926918	CLOSED 05/18 - FASB 106 (OPEB) NON SERVICE COSTS - BURDENS INDIRECT
926919	OTHER BENEFITS EXPENSE - BURDENS INDIRECT
926990	RETIREMENT INCOME EXPENSE - BURDENS INDIRECT
926994	PENSION NON SERVICE COSTS - BURDENS INDIRECT - LKS COS ONLY
926995	ADOPTION ASSISTANCE PROGRAM - INDIRECT
926997	FASB 106 (OPEB) NON SERVICE COSTS - BURDENS INDIRECT - LKS COS ONLY
926998	PENSION NON SERVICE COSTS - BURDENS INDIRECT
926999	FASB 106 (OPEB) NON SERVICE COSTS - BURDENS INDIRECT
927001	ELEC SUPPL W/O CH-DR

Oracle Account Setup Details

Account Number	Account Description
927002	OTH ITEMS W/O CH-DR
927003	CLOSED 06/18 - CITY OF LOU GAS FRAN
928001	FORMAL CASES - FERC
928002	REG UPKEEP ASSESSMTS
928003	AMORTIZATION OF RATE CASE EXPENSES
928007	FORMAL CASES - VIRGINIA
928008	FORMAL CASES - KENTUCKY
928902	REG UPKEEP ASSESSMENT - I
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	CLOSED 06/18 - RESEARCH WORK
930207	OTHER MISC GEN EXP
930217	MGP EXPENSES
930250	BROKER FEES-INDIRECT
930271	MISC CORPORATE EXP - INDIRECT
930272	ASSOCIATION DUES - INDIRECT
930274	RESEARCH AND DEVELOPMENT EXPENSES - INDIRECT
930277	OTHER MISC GEN EXP - INDIRECT
931004	RENTS-CORPORATE HQ
931100	RENTS-OTHER
931900	I/C JOINT USE RENT EXPENSE-INDIRECT
931904	RENTS - CORPORATE HQ (INDIRECT)
935101	MTCE-GEN PLANT
935191	MTCE-GEN PLANT - INDIRECT
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
951001	ECR RATE BASE - 2016 PLANS (STAT ONLY)
951002	ECR RATE BASE - PRE-2016 PLANS (STAT ONLY)
951003	ECR RATE OF RETURN - 2016 PLANS (STAT ONLY)
951004	ECR RATE OF RETURN - PRE-2016 PLANS (STAT ONLY)
951005	ECR JURISDICTIONAL FACTOR (STAT ONLY)
951006	ECR - ESTIMATED OPERATING EXPENSES (STAT ONLY)
951101	DSM DCR RECOVERABLE PROGRAM EXPENSE (STAT ONLY)
951102	DSM DRLS - LOST SALES (STAT ONLY)
951103	DSM DSMI - INCENTIVE (STAT ONLY)
951104	DSM RECOVERABLE DCCR PROGRAM EXPENSE (STAT ONLY)
951105	DSM RECOVERABLE DCCR CAPITAL EXPENSE (STAT ONLY)
951106	DSM RECOVERABLE INTEREST ON DCCR CAPITAL (STAT ONLY)
951107	DSM DBA STAT ONLY - (BALANCING ADJUSTMENT)
951201	GLT RATE BASE (STAT ONLY) - DISTR
951202	GLT DEPRECIATION SAVINGS (STAT ONLY) - DISTR
951203	GLT COST OF CAPITAL (STAT ONLY) - DISTR
951204	GLT CHANGE IN YTD AVERAGE RATE BASE, APPLIED TO ALL MONTHS (STAT ONLY) - DISTR
951205	GLT RATE BASE (STAT ONLY) - TRANS
951206	GLT DEPRECIATION SAVINGS (STAT ONLY) - TRANS
951207	GLT COST OF CAPITAL (STAT ONLY) - TRANS
951208	GLT CHANGE IN YTD AVERAGE RATE BASE, APPLIED TO ALL MONTHS (STAT ONLY) - TRANS
951301	ACTUAL MONTHLY COOLING DEGREE DAYS (STAT ONLY)
951302	ACTUAL MONTHLY HEATING DEGREE DAYS (STAT ONLY)
951303	NORMAL MONTHLY COOLING DEGREE DAYS (STAT ONLY)
951304	NORMAL MONTHLY HEATING DEGREE DAYS (STAT ONLY)
951305	ACTUAL MONTHLY AVERAGE TEMPERATURE (STAT ONLY)
951306	NORMAL MONTHLY AVERAGE TEMPERATURE (STAT ONLY)

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(n)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

The latest twelve (12) months of the monthly managerial reports providing financial results of operations in comparison to the forecast.

Response:

See attached.

Net Income Continuing Operations - Kentucky Utilities Company

September 2017

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	140,838,549	150,356,399	(9,517,850)
Cost of Revenues	(47,570,110)	(53,029,354)	5,459,244
Electric Margin	93,268,438	97,327,044	(4,058,606)
O&M	(31,353,897)	(32,793,947)	1,440,050
Other Income & Expenses	545,951	(271,223)	817,174
Depreciation	(19,422,455)	(21,083,534)	1,661,080
Property tax	(2,522,570)	(2,479,960)	(42,611)
Equity in Earnings	-	-	-
Interest	(8,045,276)	(7,958,777)	(86,499)
Income Tax	(11,816,412)	(12,142,075)	325,662
Net Income Ongoing Operations	**20,653,779**	**20,597,529**	**56,250**
Special Items	-	-	-
Net Income	**20,653,779**	**20,597,529**	**56,250**

Net Income Continuing Operations - Kentucky Utilities Company

October 2017

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	133,342,695	143,316,632	(9,973,937)
Cost of Revenues	(47,667,749)	(52,690,029)	5,022,280
Electric Margin	85,674,945	90,626,602	(4,951,657)
O&M	(33,482,488)	(38,947,488)	5,465,000
Other Income & Expenses	(44,370)	(288,443)	244,073
Depreciation	(19,450,397)	(21,169,987)	1,719,590
Property tax	(2,516,335)	(2,479,960)	(36,375)
Equity in Earnings	-	-	-
Interest	(8,037,437)	(7,988,289)	(49,148)
Income Tax	(8,522,457)	(7,452,492)	(1,069,965)
Net Income Ongoing Operations	**13,621,461**	**12,299,943**	**1,321,518**
Special Items	-	-	-
Net Income	**13,621,461**	**12,299,943**	**1,321,518**

Net Income Continuing Operations - Kentucky Utilities Company

November 2017

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	142,766,516	152,051,920	(9,285,405)
Cost of Revenues	(51,444,229)	(55,491,723)	4,047,494
Electric Margin	91,322,286	96,560,197	(5,237,911)
O&M	(31,039,595)	(30,481,363)	(558,232)
Other Income & Expenses	(182,202)	(360,943)	178,741
Depreciation	(19,464,745)	(21,289,686)	1,824,941
Property tax	(2,523,121)	(2,479,960)	(43,162)
Equity in Earnings	-	-	-
Interest	(8,019,596)	(7,983,967)	(35,629)
Income Tax	(11,537,385)	(12,978,988)	1,441,603
Net Income Ongoing Operations	**18,555,643**	**20,985,290**	**(2,429,648)**
Special Items	-	-	-
Net Income	**18,555,643**	**20,985,290**	**(2,429,648)**

Net Income Continuing Operations - Kentucky Utilities Company

December 2017

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	165,561,751	173,202,781	(7,641,029)
Cost of Revenues	(56,405,545)	(62,725,951)	6,320,405
Electric Margin	109,156,206	110,476,830	(1,320,624)
O&M	-	-	-
Other Income & Expenses	(29,880,811)	(30,235,985)	355,174
Depreciation	(228,517)	(314,334)	85,817
Property tax	(19,544,323)	(21,439,726)	1,895,403
Equity in Earnings	(2,578,151)	(2,479,960)	(98,192)
Interest	(8,123,469)	(8,006,906)	(116,563)
Income Tax	(18,416,470)	(18,074,352)	(342,118)
Net Income Ongoing Operations	**30,384,465**	**29,925,567**	**458,898**
Special Items	(174,071)	-	(174,071)
Net Income	**30,210,393**	**29,925,567**	**284,826**

Net Income Continuing Operations - Kentucky Utilities Company

January 2018

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	191,638,720	168,047,628	23,591,092
Cost of Revenues	(75,872,779)	(61,568,855)	(14,303,924)
Electric Margin	115,765,941	106,478,773	9,287,169
O&M	(28,353,496)	(30,968,620)	2,615,124
Other Income & Expenses	(572,306)	(652,042)	79,736
Depreciation	(19,719,031)	(19,868,362)	149,331
Property tax	(2,637,413)	(2,681,168)	43,755
Equity in Earnings	-	-	-
Interest	(8,259,122)	(8,400,761)	141,639
Income Tax	(14,286,054)	(11,047,294)	(3,238,761)
Net Income Ongoing Operations	**41,938,519**	**32,860,526**	**9,077,993**
Special Items	-	-	-
Net Income	**41,938,519**	**32,860,526**	**9,077,993**

Net Income Continuing Operations - Kentucky Utilities Company

February 2018

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	137,745,456	150,731,030	(12,985,575)
Cost of Revenues	(49,102,945)	(53,503,769)	4,400,824
Electric Margin	88,642,511	97,227,262	(8,584,751)
O&M	(27,323,249)	(29,719,996)	2,396,747
Other Income & Expenses	(204,628)	(306,067)	101,439
Depreciation	(19,816,063)	(19,867,522)	51,459
Property tax	(2,668,308)	(2,681,168)	12,860
Equity in Earnings	-	-	-
Interest	(8,087,948)	(8,342,974)	255,026
Income Tax	(7,675,441)	(9,092,680)	1,417,239
Net Income Ongoing Operations	**22,866,874**	**27,216,855**	**(4,349,981)**
Special Items	-	-	-
Net Income	**22,866,874**	**27,216,855**	**(4,349,981)**

Net Income Continuing Operations - Kentucky Utilities Company

March 2018

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	141,093,729	143,067,618	(1,973,889)
Cost of Revenues	(51,429,663)	(51,137,380)	(292,283)
Electric Margin	89,664,066	91,930,239	(2,266,172)
O&M	(35,047,254)	(35,945,195)	897,941
Other Income & Expenses	1,268,405	(355,397)	1,623,802
Depreciation	(19,814,781)	(19,894,338)	79,556
Property tax	(2,697,387)	(2,681,168)	(16,219)
Equity in Earnings	-	-	-
Interest	(8,172,155)	(8,426,167)	254,013
Income Tax	(2,223,546)	(3,719,906)	1,496,361
Net Income Ongoing Operations	**22,977,348**	**20,908,067**	**2,069,281**
Special Items	-	-	-
Net Income	**22,977,348**	**20,908,067**	**2,069,281**

Net Income Continuing Operations - Kentucky Utilities Company

April 2018

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	125,617,118	124,547,115	1,070,003
Cost of Revenues	(46,078,885)	(43,704,587)	(2,374,298)
Electric Margin	79,538,233	80,842,527	(1,304,294)
O&M	(34,123,623)	(37,434,677)	3,311,054
Other Income & Expenses	(1,394,856)	(301,367)	(1,093,488)
Depreciation	(19,833,771)	(19,979,561)	145,791
Property tax	(2,711,985)	(2,681,168)	(30,817)
Equity in Earnings	-	-	-
Interest	(8,323,814)	(8,526,111)	202,297
Income Tax	(2,085,629)	(2,812,489)	726,860
Net Income Ongoing Operations	**11,064,556**	**9,107,153**	**1,957,402**
Special Items	-	-	-
Net Income	**11,064,556**	**9,107,153**	**1,957,402**

Net Income Continuing Operations - Kentucky Utilities Company

May 2018

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	142,515,192	130,682,252	11,832,940
Cost of Revenues	(51,220,190)	(46,495,056)	(4,725,133)
Electric Margin	91,295,002	84,187,196	7,107,806
O&M	(30,892,105)	(32,292,702)	1,400,597
Other Income & Expenses	124,256	(226,669)	350,925
Depreciation	(19,863,113)	(20,086,562)	223,449
Property tax	(2,559,787)	(2,681,168)	121,382
Equity in Earnings	-	-	-
Interest	(8,382,351)	(8,629,126)	246,775
Income Tax	(7,229,464)	(4,961,054)	(2,268,410)
Net Income Ongoing Operations	**22,492,439**	**15,309,915**	**7,182,524**
Special Items	-	-	-
Net Income	**22,492,439**	**15,309,915**	**7,182,524**

Net Income Continuing Operations - Kentucky Utilities Company

June 2018

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	146,669,178	146,225,635	443,543
Cost of Revenues	(52,710,414)	(53,894,348)	1,183,934
Electric Margin	93,958,764	92,331,287	1,627,477
O&M	(31,874,546)	(31,171,385)	(703,161)
Other Income & Expenses	709,785	(336,781)	1,046,565
Depreciation	(19,916,623)	(20,168,981)	252,359
Property tax	(2,684,383)	(2,681,168)	(3,215)
Equity in Earnings	-	-	-
Interest	(8,321,263)	(8,645,951)	324,687
Income Tax	(4,831,759)	(4,924,139)	92,380
Net Income Ongoing Operations	**27,039,975**	**24,402,883**	**2,637,092**
Special Items	(10,450)	-	(10,450)
Net Income	**27,029,526**	**24,402,883**	**2,626,643**

Net Income Continuing Operations - Kentucky Utilities Company

July 2018

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	150,529,316	156,133,308	(5,603,991)
Cost of Revenues	(53,292,783)	(57,661,384)	4,368,601
Electric Margin	97,236,533	98,471,923	(1,235,390)
O&M	(34,654,313)	(31,405,774)	(3,248,539)
Other Income & Expenses	(351,540)	(239,610)	(111,930)
Depreciation	(19,924,710)	(20,208,161)	283,451
Property tax	(2,693,630)	(2,686,643)	(6,987)
Equity in Earnings	-	-	-
Interest	(8,271,856)	(8,631,207)	359,351
Income Tax	(7,633,300)	(8,827,644)	1,194,344
Net Income Ongoing Operations	**23,707,184**	**26,472,883**	**(2,765,699)**
Special Items	-	-	-
Net Income	**23,707,184**	**26,472,883**	**(2,765,699)**

Net Income Continuing Operations - Kentucky Utilities Company

August 2018

Month To Date Actual VS Month to Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	152,583,695	158,860,930	(6,277,235)
Cost of Revenues	(54,502,165)	(58,098,145)	3,595,980
Electric Margin	98,081,530	100,762,785	(2,681,255)
O&M	(33,156,213)	(32,448,357)	(707,856)
Other Income & Expenses	251,005	(221,199)	472,204
Depreciation	(19,957,542)	(20,239,545)	282,003
Property tax	(2,720,212)	(2,686,643)	(33,569)
Equity in Earnings	0	0	0
Interest	(8,295,685)	(8,592,274)	296,589
Income Tax	(8,347,468)	(9,153,787)	806,319
Net Income Ongoing Operations	**25,855,415**	**27,420,980**	**(1,565,566)**
Special Items	-	-	-
Net Income	**25,855,415**	**27,420,980**	**(1,565,566)**

Kentucky Utilities Company
Case No. 2018-00294
Forecasted Test Period Filing Requirements
(Forecasted Test Period 12ME 4/30/20; Base Period 12ME 12/31/18)

Filing Requirement
807 KAR 5:001 Section 16(7)(o)
Sponsoring Witness: Daniel K. Arbough

Description of Filing Requirement:

Complete monthly budget variance reports, with narrative explanations, for the twelve (12) months immediately prior to the base period, each month of the base period, and any subsequent months, as they become available.

Response:

The Companies have only one monthly budget variance (performance) report used for management reporting to the CEO and executive officers. Certain information responsive to this request is being provided under seal pursuant to a Petition for Confidential Protection.

See attached for the monthly reports for:

- The twelve months prior to the base period - - January 2017 through December 2017.
- Each month of the base period - As of the date of the filing only the months of January 2018 through July 2018 are available. The Company will provide this data for the remaining periods requested in the upcoming months as it becomes available.

Performance Report

January 2017

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Kentucky Regulated Dashboard — January 2017

	Current Month		Full Year	
Safety	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees[1]	0.46	0.90	1.35	1.12
Employee lost-time incidents	0	0	8	5
Reliability	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,917	3,213	34,129	34,425
Utility EFOR	2.8%	5.5%	N/A	5.5%
Utility EAF	85.1%	92.5%	N/A	85.2%
Steam Fleet Commercial Availability	94.3%	93.0%	N/A	93.0%
Combined SAIFI	0.08	0.09	N/A	1.03
Combined SAIDI (minutes)	6.11	7.81	N/A	93.20
GwH Sales	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	1,040	1,174	10,533	10,668
Commercial	657	678	7,860	7,882
Industrial	712	786	9,631	9,706
Municipals	158	175	1,828	1,846
Other	226	236	2,744	2,753
Off-System Sales	71	21	294	244
Total	2,864	3,070	32,890	33,098
Weather-Normalized Sales Growth	**TTM**			
Residential	-1.15%			
Commercial	3.95%			
Industrial	-3.47%			
Municipal	0.22%			
Other	0.89%			
Total	-0.38%			

	Current Month		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$160	$171	$1,936	$1,948
Gas Margins	$24	$25	$181	$183
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$46	$52	$1,107	$1,107
O&M ($ millions)[2]	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$55	$56	$749	$749
Head Count	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,516	3,605	3,591	3,591
Other Metrics	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	1	0	N/A	3
NERC Possible Violations[3]	1	0	N/A	5

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
ROE[4]	9.8%	9.8%	9.8%

Variance Explanations

• Lower margins primarily due to lower sales volumes from warmer than average weather resulting in lower retail electric base energy and demand revenue of $12 million.

Major Developments

• In both Louisville and Lexington, January 2017 ranked as the second warmest in the past 20 years. The month of February has also begun with a similar weather pattern and mild temperatures. Retail load continues to be impacted by these conditions.

• LKE employees' continued focus on the customer experience has led to another J.D. Power award. LG&E was named the top-ranking utility in the Midwest segment in the newly released J.D. Power and Associates 2016 Calendar-Year Gas Business Customer Satisfaction Study. In the survey, the Company also was recognized as the top performer nationwide in the customer service category. Between LG&E and KU, the Utilities were the top-ranked utility within their respective segments in all four J.D. Power studies this past year.

• The Company filed over 3,400 responses to data requests (first round with intervenors) in its rate cases at the KPSC, and is addressing responses to 1,500 supplemental data requests which are due on February 20. The formal public hearing has also been scheduled to begin on May 2.

• Company representatives were joined by Lexington city and community leaders to unveil KU's new publicly available electric vehicle charging station. LKE has installed three charging stations in Louisville and two in Lexington. There are three additional stations planned for both the LG&E and KU service territories during 2017.

(1) Full year forecast amount shown represents target.
(2) Net of cost recovery mechanisms.
(3) The possible violation issues for YTD Actual is believed to be minimal risk.
(4) Excludes goodwill and other purchase accounting adjustments.

Significant Future Events

• Regarding the Kentucky rate cases, intervenor testimony will be filed March 3, and the Company's rebuttal testimony will be submitted April 14.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated

January 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 251	$ 268	$ (17)	Due primarily to lower sales volumes driven by mild weather.
Gas Revenues	48	54	(7)	Due primarily to lower sales volumes driven by mild weather.
Total Revenues	299	322	(24)	
Cost of Sales:				
Fuel Electric Costs	72	78	6	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	24	29	6	Due to lower gas usage (mild weather).
Purchased Power	5	5	(0)	
Other Electric Cost	14	14	0	
Total Cost of Sales	115	126	11	
Gross Margin:				
Electric Margin	160	171	(11)	Lower margins primarily due to lower sales volumes from warmer than average weather resulting in lower retail electric base energy and demand revenue.
Gas Margin	24	25	(1)	
Total Gross Margin	184	196	(12)	
Operating Expenses:				
O&M	55	56	2	
Depreciation & Amortization	30	30	0	
Taxes, Other than Income	5	5	0	
Total Operating Expenses	89	91	2	
Other income (expense)	(1)	(1)	(0)	
EBIT	94	104	(10)	
Interest Expense	18	18	0	
Income from Ongoing Operations before income taxes	76	86	(10)	
Income Tax Expense	29	33	4	
Net Income (loss) from ongoing operations	**47**	**53**	**$ (6)**	
Discontinued Operations	(0)	(0)	0	
Net Income (loss)	$ 47	$ 53	$ (6)	
KY Regulated Financing Costs	(3)	$ (3)	(0)	
KY Regulated Net Income	$ 45	$ 50	$ (6)	
Earnings Per Share - Ongoing	$ 0.07	$ 0.07	$ (0.01)	

Note: Schedules may not sum due to rounding.

Case Nos. 2018-00294 and 2018-00295
Attachment to Filing Requirement
807 KAR 5:001 Sec. 16(7)(o)

Arbough

Income Statement: Actual vs. Budget (YTD) - LG&E — January 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 98	$ 99	$ (1)	
Gas Revenues	48	54	(7)	Due primarily to lower sales volumes driven by mild weather.
Total Revenues	145	153	(8)	
Cost of Sales:				
Fuel Electric Costs	31	29	(2)	
Gas Supply Expenses	24	29	6	Due to lower gas usage (mild weather)
Purchased Power	4	4	0	
Other Electric Cost	5	6	0	
Total Cost of Sales	64	68	4	
Gross Margin:				
Electric Margin	57	60	(3)	
Gas Margin	24	25	(1)	
Total Gross Margin	81	85	(4)	
Operating Expenses:				
O&M	24	26	1	
Depreciation & Amortization	12	12	0	
Taxes, Other than Income	2	2	0	
Total Operating Expenses	39	40	2	
Other income (expense)	(1)	(0)	(0)	
EBIT	42	45	(3)	
Interest Expense	6	6	0	
Income from Ongoing Operations before income taxes	36	39	(3)	
Income Tax Expense	14	15	1	
Net Income (loss) from ongoing operations	**22**	**24**	**$ (2)**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU

January 2017

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 160	$ 175	$ (15)	Due primarily to lower sales volumes driven by mild weather.
Gas Revenues	0	0	0	
Total Revenues	160	175	(15)	
Cost of Sales:				
Fuel Electric Costs	42	49	7	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	0	0	0	
Purchased Power	7	7	(0)	
Other Electric Cost	8	9	0	
Total Cost of Sales	58	64	7	
Gross Margin:				
Electric Margin	103	111	(8)	See explanation above
Gas Margin	0	0	0	
Total Gross Margin	103	111	(8)	
Operating Expenses:				
O&M	29	29	0	
Depreciation & Amortization	18	18	0	
Taxes, Other than Income	2	2	0	
Total Operating Expenses	49	50	1	
Other income (expense)	(1)	(1)	0	
EBIT	53	61	(8)	
Interest Expense	8	8	(0)	
Income from Ongoing Operations before income taxes	45	53	(8)	
Income Tax Expense	17	20	3	
Net Income (loss) from ongoing operations	**28**	**32**	**(5)**	

Note: Schedules may not sum due to rounding.

O&M — January 2017

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	14	13	(1)	0	(0)	(0)	(0)	(0)
Project Engineering	0	0	0	0	0	0	0	0
Transmission	2	3	1	(0)	0	0	0	0
Energy Supply and Analysis	1	1	0	(0)	0	0	0	0
Generation Services	1	1	0	(0)	(0)	(0)	(0)	0
Electric Distribution	5	6	1	0	1	0	0	0
Gas Distribution and AMS2	3	3	0	0	0	(0)	0	(0)
Safety and Technical Training	0	0	(0)	(0)	(0)	0	(0)	0
Customer Services	7	8	1	0	0	0	0	0
Senior VP Operations	**34**	**35**	**1**	**0**	**1**	**(0)**	**(0)**	**0**
Audit Services	0	0	0	0	0	(0)	0	0
Controller	1	1	(0)	(0)	0	0	(0)	(0)
Supply Chain	0	0	0	0	0	0	(0)	0
Treasurer	2	2	(0)	(0)	0	0	(0)	0
State Regulation and Rates	0	0	(0)	(0)	0	0	(0)	0
Chief Financial Officer	**4**	**4**	**(0)**	**(0)**	**0**	**0**	**(0)**	**0**
General Counsel	**2**	**2**	**0**	**0**	**0**	**0**	**(0)**	**0**
Human Resources	**1**	**1**	**0**	**0**	**0**	**(0)**	**(0)**	**0**
Information Technology	**4**	**5**	**0**	**0**	**(0)**	**0**	**0**	**0**
Corporate	**10**	**10**	**0**	**0**	**0**	**0**	**(0)**	**(0)**
Enterprise Security	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
O&M Total MTD	**55**	**56**	**2**	**1**	**1**	**0**	**(0)**	**0**

Note: Schedules may not sum due to rounding.

Financing Activities — January 2017

($ Millions)

Balance Sheet	YTD Actual		YTD Budget		YTD Variance	
PCB						
Beg Bal	$	898.8	$	898.8	$	0.0
End Bal		898.8		898.8		0.0
Ave Bal	**$**	**898.8**	**$**	**898.8**	**$**	**0.0**
Interest Exp	**$**	**1.1**	**$**	**1.0**	**$**	**(0.1)**
Rate		**1.44%**		**1.33%**		**-0.11%**
FMB/Sr Nts/Loan with PPL						
Beg Bal	$	4,210.0	$	4,210.0	$	0.0
End Bal		4,210.0		4,210.0		0.0
Ave Bal	**$**	**4,210.0**	**$**	**4,210.0**	**$**	**0.0**
Interest Exp	**$**	**14.8**	**$**	**15.4**	**$**	**0.6**
Rate		**4.07%**		**4.24%**		**0.16%**
Short-term Debt						
Beg Bal	$	348.1	$	509.7	$	161.6
End Bal		317.8		432.7		114.9
Ave Bal	**$**	**332.9**	**$**	**471.2**	**$**	**138.3**
Interest Exp	**$**	**0.4**	**$**	**0.5**	**$**	**0.1**
Rate		**1.52%**		**1.28%**		**-0.24%**
Unamortized Debt Expense Bonds						
Beg Bal	$	(44.0)	$	(44.0)	$	0.0
End Bal		(43.7)		(42.8)		0.9
Ave Bal	**$**	**(43.8)**	**$**	**(43.4)**	**$**	**0.5**
Total End Bal	**$**	**5,382.9**	**$**	**5,498.8**	**$**	**115.9**
Total Average Bal	**$**	**5,397.9**	**$**	**5,536.6**	**$**	**138.7**
Total Expense Excl I/C [1]	**$**	**17.7**	**$**	**17.8**	**$**	**0.1**
Rate		**3.77%**		**3.70%**		**-0.07%**

[1] Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity		Borrowed[2]		Letters of Credit Issued		Unused Capacity	
LKE	$	300	$	137			$	163
LG&E		500		158				342
KU		598		23	$	198		377
TOTAL	$	1,398	$	318	$	198	$	882

[2] LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2017 Actual YTD	LKE 2017 Budget YTD	LG&E 2017 Actual YTD	LG&E 2017 Budget YTD	KU 2017 Actual YTD	KU 2017 Budget YTD
CFO pre-WC / Debt	20%	18%	27%	26%	25%	27%
CFO pre-WC + Interest / Interest	6.0	5.8	7.9	7.9	7.2	7.6
CFO pre-WC - Dividends / Debt	15%	15%	24%	25%	16%	18%
Debt to Capitalization[2]	47%	48%	38%	38%	38%	38%

Credit Metrics Moody's	LKE 2017 BP 2018	LKE 2017 BP 2019	LG&E 2017 BP 2018	LG&E 2017 BP 2019	KU 2017 BP 2018	KU 2017 BP 2019
CFO pre-WC / Debt	18%	18%	27%	29%	26%	26%
CFO pre-WC + Interest / Interest	6.0	5.7	8.5	8.7	7.8	7.6
CFO pre-WC - Dividends / Debt	11%	15%	25%	22%	20%	18%
Debt to Capitalization[2]	50%	49%	38%	36%	37%	37%

[1] Actuals represent a trailing 12 months.
[2] For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Low Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	19% - 27%	11% - 19%	5% - 11%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	15% - 23%	7% - 15%	0% - 7%
Debt / Capitalization	7.5%	40% - 50%	50% - 59%	59% - 67%

As of December 31, 2016 Issuer	Senior Unsecured Moody's	Senior Secured Moody's	Commercial Paper Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.
Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.
Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.
Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated

January 2017

($ Millions)

	1/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 14	$ 16	$ (2)	
Accounts Receivable (Trade)	429	451	(23)	
Inventory	285	271	13	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	20	19	1	
Prepayments and other current assets	43	40	4	
Total Current Assets	791	798	(7)	
Property, Plant, and Equipment	11,605	11,654	(49)	
Intangible Assets	94	96	(2)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	827	907	(80)	
Goodwill	997	997	0	
Other Long-term Assets	78	82	(4)	
Total Assets	**$ 14,393**	**$ 14,534**	**$ (141)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 214	$ 224	$ (10)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	56	55	1	
Derivative Liability	4	6	(2)	
Accrued Taxes	93	34	59	Increase is primarily due to the timing of property tax payments that were assumed to occur in Q4 2016 in the budget and accrual of 2016 extension settlement.
Regulatory Liabilities Current	14	24	(9)	
Other Current Liabilities	223	224	(1)	
Total Current Liabilities	605	566	39	
Debt - Affiliated Company	537	573	(36)	
Debt [1]	4,846	4,926	(80)	
Total Debt	5,383	5,499	(116)	
Deferred Tax Liabilities	1,735	1,735	(0)	
Investment Tax Credit	132	131	1	
Accum Provision for Pension & Related Benefits	335	411	(76)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	373	359	13	
Regulatory Liabilities Non Current	900	872	27	
Derivative Liability	26	33	(6)	Due to change in market interest rates and termination of interest rate swap in December 2016.
Other Liabilities	191	199	(8)	
Total Deferred Credits and Other Liabilities	3,691	3,740	(48)	
Equity	4,714	4,730	(16)	
Total Liabilities and Equity	**$ 14,393**	**$ 14,534**	**$ (141)**	

[1] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

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Balance Sheet - LG&E

January 2017

($ Millions)

	1/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 5	$ 5	$ 0	
Accounts Receivable (Trade)	193	200	(7)	
Inventory	129	126	2	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	10	4	6	
Prepayments and other current assets	73	50	23	Primarily due to increase in accounts receivable from associated company related to federal income tax settlement.
Total Current Assets	409	386	23	
Property, Plant, and Equipment	5,001	5,037	(36)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	449	503	(53)	
Goodwill	0	0	0	
Other Long-term Assets	17	21	(4)	
Total Assets	**$ 5,883**	**$ 5,953**	**$ (70)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 147	$ 153	$ (6)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	27	26	1	
Derivative Liability	4	6	(2)	
Accrued Taxes	80	18	62	Increase is primarily due to the timing of property tax payments that were assumed to occur in Q4 2016 in the budget and accrual of 2016 extension settlement.
Regulatory Liabilities Current	3	5	(2)	
Other Current Liabilities	89	93	(4)	
Total Current Liabilities	350	302	48	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	1,776	1,831	(55)	
Total Debt	1,776	1,831	(55)	
Deferred Tax Liabilities	974	973	1	
Investment Tax Credit	36	36	(0)	
Accum Provision for Pension & Related Benefits	53	77	(24)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	103	99	4	
Regulatory Liabilities Non Current	367	358	9	
Derivative Liability	26	33	(6)	
Other Liabilities	88	92	(4)	
Total Deferred Credits and Other Liabilities	1,648	1,668	(20)	
Equity	2,109	2,152	(43)	
Total Liabilities and Equity	**$ 5,883**	**$ 5,953**	**$ (70)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

Balance Sheet - KU

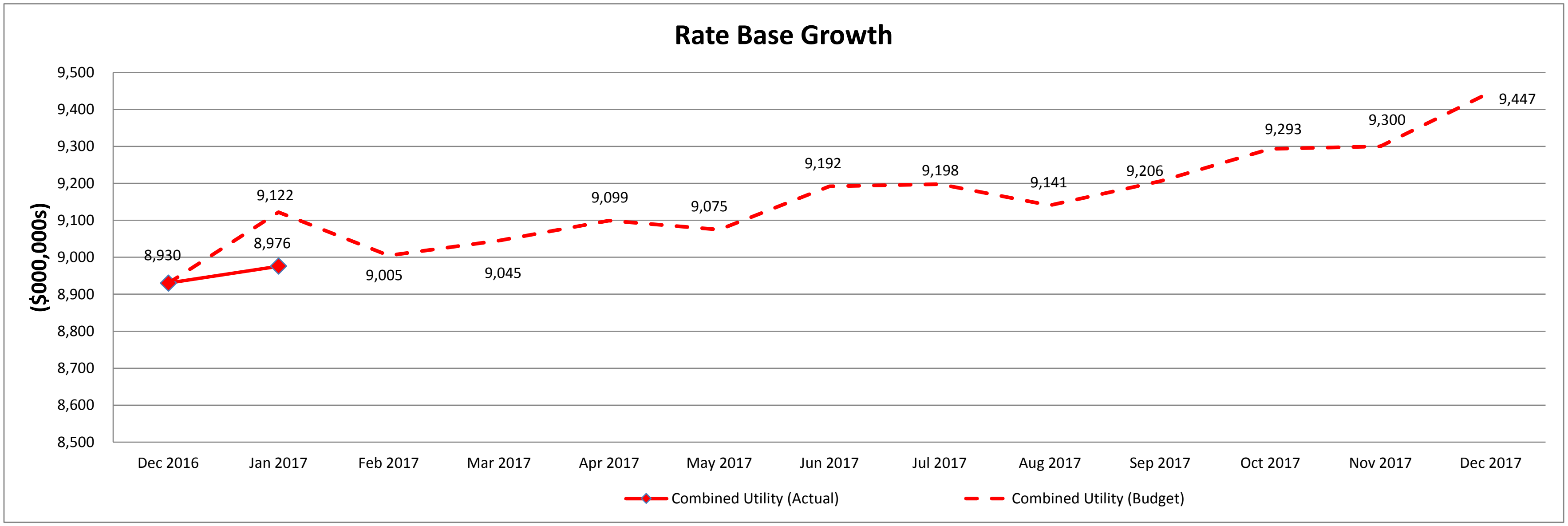
January 2017

($ Millions)

	1/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 9	$ 5	$ 3	
Accounts Receivable (Trade)	236	251	(15)	
Inventory	156	145	11	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	10	15	(4)	
Prepayments and other current assets	21	20	1	
Total Current Assets	432	436	(4)	
Property, Plant, and Equipment	6,596	6,608	(12)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	375	402	(27)	
Goodwill	0	0	0	
Other Long-term Assets	58	58	0	
Total Assets	**$ 7,474**	**$ 7,516**	**$ (43)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 143	$ 115	$ 29	Increase is primarily due to an increase in accounts payable to an associated company related to federal income tax settlement.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	29	28	1	
Derivative Liability	0	0	0	
Accrued Taxes	36	23	13	Increase is primarily due to the timing of property tax payments that were assumed to occur in Q4 2016 in the budget.
Regulatory Liabilities Current	11	18	(7)	
Other Current Liabilities	74	76	(1)	
Total Current Liabilities	294	259	34	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,348	2,372	(25)	
Total Debt	2,348	2,372	(25)	
Deferred Tax Liabilities	1,170	1,206	(35)	
Investment Tax Credit	96	95	1	
Accum Provision for Pension & Related Benefits	45	67	(21)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	269	260	9	
Regulatory Liabilities Non Current	457	438	20	
Derivative Liability	0	0	0	
Other Liabilities	50	53	(3)	
Total Deferred Credits and Other Liabilities	2,088	2,118	(30)	
Equity	2,744	2,767	(22)	
Total Liabilities and Equity	**$ 7,474**	**$ 7,516**	**$ (43)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

Combined KU and LG&E Rate Base Growth	January 2017



Performance Report

February 2017

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Kentucky Regulated Dashboard

February 2017

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees(1)	1.47	0.37	1.02	0.61	1.35	1.12
Employee lost-time incidents	2	0	2	0	10	5
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,382	2,838	5,299	6,051	33,673	34,425
Utility EFOR	7.1%	5.5%	4.8%	5.5%	N/A	5.5%
Utility EAF	84.1%	91.2%	85.4%	91.9%	N/A	85.2%
Steam Fleet Commercial Availability	89.5%	93.0%	91.9%	93.0%	N/A	93.0%
Combined SAIFI	0.04	0.06	0.12	0.15	N/A	1.03
Combined SAIDI (minutes)	3.41	4.89	9.52	12.70	N/A	93.20
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	708	962	1,748	2,136	10,280	10,668
Commercial	571	617	1,228	1,295	7,814	7,882
Industrial	691	734	1,403	1,521	9,588	9,706
Municipals	132	162	290	338	1,798	1,846
Other	205	217	431	452	2,732	2,753
Off-System Sales	7	24	78	45	274	244
Total	2,314	2,716	5,178	5,787	32,485	33,098
Weather-Normalized Sales Growth			**TTM**			
Residential			-1.23%			
Commercial			2.79%			
Industrial			-4.41%			
Municipal			-0.52%			
Other			-0.39%			
Total			-1.11%			

	Current Month		YTD		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$138	$156	$299	$327	$1,912	$1,948
Gas Margins	$22	$23	$46	$48	$180	$183
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$50	$57	$97	$110	$1,107	$1,107
O&M ($ millions)(2)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$55	$57	$109	$113	$749	$749
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,489	3,604	3,489	3,604	3,584	3,591
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	1	0	2	0	N/A	3
NERC Possible Violations(3)	0	0	1	0	N/A	5

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
ROE(4)	9.7%	9.5%	9.8%

Variance Explanations

• Lower current month margins primarily due to lower sales volumes from warmer than average weather resulting in lower retail electric base energy and demand revenue of $19 million.

• Lower margins YTD primarily due to lower sales volumes from warmer than average weather resulting in lower retail electric base energy and demand revenue of $31 million.

(1) Full year forecast amount shown represents target.

(2) Net of cost recovery mechanisms.

(3) The possible violation issues for YTD Actual is believed to be minimal risk.

(4) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Major Developments

• February 2017 represented the warmest February on record for both Louisville and Lexington. Louisville also reached 81 degrees on the 24th, setting a new all-time high for the month. Retail sales continue to be impacted by these conditions.

• LKE filed nearly 1,500 responses to supplemental data requests in the rate case proceeding and is currently analyzing intervenors' testimony from 34 different witnesses. The Company's rebuttal testimony will be submitted on April 14.

• After the Companies' 2011 ECR plans were approved by the KPSC, the Commission hired an external consultant to monitor and report on the construction progress for the approved projects. LKE filed its final quarterly report to the KPSC in January. The Company received a letter of acknowledgement from the KPSC noting that the approved projects achieved an outstanding safety record and were completed significantly under budget and on schedule. The KPSC also commended our efforts in keeping its consultant and the KPSC informed regarding the progress of the projects as well as the Company's professionalism during the review.

• Two of LKE's Research and Development projects have been honored by the Electric Power Research Institute ("EPRI"). The Company's electric vehicle charging station program was recognized with a "Technology Transfer" award for applying EPRI methods and standards in designing and deploying its charging stations. LKE also received a similar honor for its 10-megawatt universal solar facility at E.W. Brown Generating Station.

• The Trimble County Landfill Project received its permit from the Kentucky Division of Waste Management, the second of three key environmental regulatory approvals needed to begin construction of the landfill. The final permit is still being processed by the Corps of Engineers.

• The court dismissed PPL as a defendant and also dismissed the remaining federal law claim involving alleged operation of the Cane Run facility under an expired air permit. The court had previously dismissed the other federal law claims regarding dust emissions from the Cane Run power plant in 2014. The court has directed the parties to file briefs addressing whether the court should exercise supplemental jurisdiction to hear the state law claims remaining in the case.

Significant Future Events

•Regarding the Kentucky rate cases, a formal public hearing is scheduled to begin on May 2.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated

February 2017

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 213	$ 243	$ (29)	Due primarily to lower sales volumes driven by mild weather.
Gas Revenues	38	50	(12)	Due primarily to lower sales volumes driven by mild weather.
Total Revenues	251	292	(41)	
Cost of Sales:				
Fuel Electric Costs	58	69	11	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	16	27	11	Due to lower gas usage (mild weather).
Purchased Power	5	5	0	
Other Electric Cost	13	13	0	
Total Cost of Sales	91	113	23	
Gross Margin:				
Electric Margin	138	156	(18)	Lower margins primarily due to lower sales volumes from warmer than average weather resulting in lower retail electric base energy and demand revenue.
Gas Margin	22	23	(1)	
Total Gross Margin	160	179	(18)	
Operating Expenses:				
O&M	55	57	2	
Depreciation & Amortization	30	30	0	
Taxes, Other than Income	4	5	1	
Total Operating Expenses	89	92	3	
Equity in Earnings	0	0	0	
Other income (expense)	(1)	(1)	(0)	
EBIT	70	86	(16)	
Interest Expense	17	18	0	
Income from Ongoing Operations before income taxes	52	68	(16)	
Income Tax Expense	20	26	6	
Net Income (loss) from ongoing operations	**32**	**42**	**(10)**	
Discontinued Operations	(0)	(0)	0	
Net Income (loss)	$ 32	$ 42	$ (10)	
KY Regulated Financing Costs	(2)	$ (2)	(0)	
KY Regulated Net Income	$ 30	$ 40	$ (10)	
Earnings Per Share - Ongoing	$ 0.04	$ 0.06	$ (0.01)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated

February 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 465	$ 510	$ (46)	Due primarily to lower sales volumes driven by mild weather.
Gas Revenues	85	104	(19)	Due primarily to lower sales volumes driven by mild weather.
Total Revenues	550	614	(65)	
Cost of Sales:				
Fuel Electric Costs	130	146	17	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	39	56	17	Due primarily to lower gas usage as a result of mild weather.
Purchased Power	10	10	0	
Other Electric Cost	27	27	0	
Total Cost of Sales	206	239	34	
Gross Margin:				
Electric Margin	299	327	(29)	Lower margins primarily due to lower sales volumes from warmer than average weather resulting in lower retail electric base energy and demand revenue.
Gas Margin	46	48	(2)	
Total Gross Margin	344	375	(31)	
Operating Expenses:				
O&M	110	113	3	
Depreciation & Amortization	59	60	1	
Taxes, Other than Income	9	10	1	
Total Operating Expenses	178	183	5	
Other income (expense)	(2)	(2)	(0)	
EBIT	164	190	(26)	
Interest Expense	35	35	0	
Income from Ongoing Operations before income taxes	128	154	(26)	
Income Tax Expense	49	59	11	
Net Income (loss) from ongoing operations	**80**	**95**	**(15)**	
Discontinued Operations	(0)	(0)	0	
Net Income (loss)	$ 80	$ 95	$ (15)	
KY Regulated Financing Costs	(5)	$ (5)	(0)	
KY Regulated Net Income	$ 75	$ 90	$ (15)	
Earnings Per Share - Ongoing	$ 0.11	$ 0.13	$ (0.02)	

Note: Schedules may not sum due to rounding.

Case Nos. 2018-00294 and 2018-00295
Attachment to Filing Requirement
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Arbough

Income Statement: Actual vs. Budget (YTD) - LG&E — February 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 182	$ 189	$ (7)	Due primarily to lower sales volumes driven by mild weather.
Gas Revenues	85	104	(19)	Due primarily to lower sales volumes driven by mild weather.
Total Revenues	267	293	(26)	
Cost of Sales:				
Fuel Electric Costs	56	55	(1)	
Gas Supply Expenses	39	56	17	Due primarily to lower gas usage as a result of mild weather.
Purchased Power	7	8	1	
Other Electric Cost	11	11	0	
Total Cost of Sales	114	130	17	
Gross Margin:				
Electric Margin	108	115	(7)	See explanation above
Gas Margin	46	48	(2)	
Total Gross Margin	154	163	(9)	
Operating Expenses:				
O&M	48	51	3	
Depreciation & Amortization	24	24	0	
Taxes, Other than Income	5	5	0	
Total Operating Expenses	77	80	4	
Other income (expense)	(1)	(1)	(0)	
EBIT	76	82	(6)	
Interest Expense	11	12	0	
Income from Ongoing Operations before income taxes	65	70	(5)	
Income Tax Expense	25	27	2	
Net Income (loss) from ongoing operations	**40**	**43**	**(3)**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU

February 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 296	$ 334	$ (38)	Due primarily to lower sales volumes driven by mild weather.
Gas Revenues	0	0	0	
Total Revenues	296	334	(38)	
Cost of Sales:				
Fuel Electric Costs	75	92	17	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	0	0	0	
Purchased Power	14	13	(1)	
Other Electric Cost	16	17	0	
Total Cost of Sales	105	122	17	
Gross Margin:				
Electric Margin	191	212	(22)	See explanation above
Gas Margin	0	0	0	
Total Gross Margin	191	212	(22)	
Operating Expenses:				
O&M	57	59	1	
Depreciation & Amortization	35	36	0	
Taxes, Other than Income	5	5	0	
Total Operating Expenses	97	99	2	
Other income (expense)	(1)	(1)	0	
EBIT	92	112	(20)	
Interest Expense	16	16	(0)	
Income from Ongoing Operations before income taxes	76	96	(20)	
Income Tax Expense	29	37	8	
Net Income (loss) from ongoing operations	**47**	**59**	**(12)**	

Note: Schedules may not sum due to rounding.

O&M								February 2017
($ Millions)								
	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	13	14	0	1	0	(0)	0	(0)
Project Engineering	0	0	0	0	0	(0)	(0)	0
Transmission	2	3	0	(0)	(0)	0	(0)	(0)
Energy Supply and Analysis	1	1	(0)	(0)	0	0	(0)	(0)
Generation Services	1	1	(0)	(0)	0	0	(0)	(0)
Electric Distribution	5	6	1	0	1	(0)	0	(0)
Gas Distribution and AMS2	3	3	(0)	(0)	(0)	0	0	(0)
Safety and Technical Training	1	1	(0)	(0)	(0)	(0)	0	(0)
Customer Services	7	8	1	(0)	0	(0)	0	0
Senior VP Operations	**34**	**35**	**2**	**0**	**1**	**0**	**0**	**(0)**
Audit Services	0	0	0	0	0	0	0	(0)
Controller	1	1	(0)	(0)	0	0	0	(0)
Supply Chain	0	0	(0)	(0)	(0)	(0)	(0)	0
Treasurer	2	2	(0)	(0)	0	0	(0)	(0)
State Regulation and Rates	0	0	(0)	(0)	0	0	(0)	0
Chief Financial Officer	**3**	**3**	**(0)**	**(0)**	**(0)**	**0**	**(0)**	**(0)**
General Counsel	**3**	**3**	**(0)**	**(0)**	**0**	**(0)**	**0**	**0**
Human Resources	**1**	**1**	**(0)**	**0**	**0**	**(0)**	**(0)**	**(0)**
Information Technology	**4**	**4**	**0**	**(0)**	**0**	**0**	**(0)**	**0**
Corporate	**10**	**10**	**0**	**0**	**0**	**0**	**(0)**	**0**
Enterprise Security	**0**	**0**	**(0)**	**(0)**	**0**	**0**	**0**	**0**
O&M Total MTD	**55**	**57**	**2**	**0**	**1**	**0**	**0**	**(0)**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	28	27	(1)	1	0	(0)	(0)	(1)
Project Engineering	0	0	0	0	0	(0)	(0)	0
Transmission	5	5	1	(0)	0	1	(0)	(0)
Energy Supply and Analysis	2	1	(0)	(0)	0	0	0	0
Generation Services	2	2	(0)	(0)	0	(0)	(0)	0
Electric Distribution	10	12	2	0	2	(0)	0	0
Gas Distribution and AMS	5	5	(0)	0	0	(0)	0	(0)
Safety and Technical Training	1	1	(0)	(0)	(0)	(0)	(0)	0
Customer Services	15	16	1	0	0	0	0	1
SVP Operations	**68**	**71**	**3**	**1**	**2**	**0**	**(0)**	**(0)**
Audit Services	0	0	0	0	0	(0)	0	(0)
Controller	1	1	(0)	(0)	0	0	0	(0)
Supply Chain	1	1	(0)	(0)	(0)	(0)	(0)	0
Treasurer	4	4	(0)	(0)	0	0	(0)	(0)
State Regulation and Rates	1	1	(0)	(0)	0	0	(0)	0
Chief Financial Officer	**7**	**7**	**(0)**	**(0)**	**(0)**	**0**	**(0)**	**(0)**
General Counsel	**5**	**5**	**0**	**0**	**0**	**(0)**	**(0)**	**0**
Human Resources	**1**	**1**	**0**	**0**	**0**	**(0)**	**(0)**	**(0)**
Information Technology	**9**	**9**	**0**	**(0)**	**(0)**	**0**	**(0)**	**0**
Corporate	**20**	**20**	**0**	**0**	**0**	**0**	**(0)**	**(0)**
Enterprise Security	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
O&M Total YTD	**109**	**113**	**3**	**1**	**2**	**0**	**(0)**	**0**

Note: Schedules may not sum due to rounding.

Financing Activities February 2017

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance
PCB			
Beg Bal	$ 898.8	$ 898.8	$ 0.0
End Bal	898.8	898.8	0.0
Ave Bal	**$ 898.8**	**$ 898.8**	**$ 0.0**
Interest Exp	**$ 2.2**	**$ 2.1**	**$ (0.1)**
Rate	**1.49%**	**1.39%**	**-0.10%**
FMB/Sr Nts/Loan with PPL			
Beg Bal	$ 4,210.0	$ 4,210.0	$ 0.0
End Bal	4,210.0	4,210.0	0.0
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ 0.0**
Interest Exp	**$ 30.6**	**$ 30.7**	**$ 0.2**
Rate	**4.43%**	**4.45%**	**0.02%**
Short-term Debt			
Beg Bal	$ 348.1	$ 432.7	$ 84.6
End Bal	255.7	333.5	77.7
Ave Bal	**$ 301.9**	**$ 383.1**	**$ 81.2**
Interest Exp	**$ 0.8**	**$ 0.9**	**$ 0.2**
Rate	**1.52%**	**1.47%**	**-0.05%**
Unamortized Debt Expense Bonds			
Beg Bal	$ (44.0)	$ (42.8)	$ 1.2
End Bal	(43.4)	(42.3)	1.1
Ave Bal	**$ (43.7)**	**$ (42.6)**	**$ 1.2**
Total End Bal	**$ 5,321.1**	**$ 5,399.9**	**$ 78.9**
Total Average Bal	**$ 5,367.0**	**$ 5,449.3**	**$ 82.3**
Total Expense Excl I/C [(1)]	**$ 35.1**	**$ 35.4**	**$ 0.3**
Rate	**3.96%**	**3.94%**	**-0.02%**

[(1)] Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed[(2)]	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 128		$ 172
LG&E	500	110		390
KU	598	18	$ 198	382
TOTAL	$ 1,398	$ 256	$ 198	$ 944

[(2)] LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2017 Actual YTD	LKE 2017 Budget YTD	LG&E 2017 Actual YTD	LG&E 2017 Budget YTD	KU 2017 Actual YTD	KU 2017 Budget YTD
CFO pre-WC / Debt	19%	19%	28%	27%	25%	27%
CFO pre-WC + Interest / Interest	5.9	5.8	7.8	7.9	7.0	7.6
CFO pre-WC - Dividends / Debt	15%	15%	25%	26%	15%	18%
Debt to Capitalization[2]	47%	47%	38%	38%	38%	37%

Credit Metrics Moody's	LKE 2017 BP 2018	LKE 2017 BP 2019	LG&E 2017 BP 2018	LG&E 2017 BP 2019	KU 2017 BP 2018	KU 2017 BP 2019
CFO pre-WC / Debt	18%	18%	27%	29%	26%	26%
CFO pre-WC + Interest / Interest	6.0	5.7	8.5	8.7	7.8	7.6
CFO pre-WC - Dividends / Debt	11%	15%	25%	22%	20%	18%
Debt to Capitalization[2]	50%	49%	38%	36%	37%	37%

(1) Actuals represent a trailing 12 months.
(2) For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Low Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	19% - 27%	11% - 19%	5% - 11%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	15% - 23%	7% - 15%	0% - 7%
Debt / Capitalization	7.5%	40% - 50%	50% - 59%	59% - 67%

As of December 31, 2016	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated

February 2017

($ Millions)

	2/28/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 17	$ 27	$ (10)	Decrease primarily related to higher budgeted temporary investments.
Accounts Receivable (Trade)	397	430	(32)	
Inventory	279	254	25	Higher inventory levels due to decreased fuel burn as a result of lower generation
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	23	21	3	
Prepayments and other current assets	45	37	8	
Total Current Assets	761	768	(6)	
Property, Plant, and Equipment	11,617	11,670	(53)	
Intangible Assets	93	95	(2)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	827	909	(82)	
Goodwill	997	997	0	
Other Long-term Assets	77	81	(4)	
Total Assets	**$ 14,374**	**$ 14,521**	**$ (148)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 214	$ 223	$ (9)	
Dividends Payable to Affiliated Companies	102	0	102	Dividends are considered declared and paid in the same month in the budget.
Customer Deposits	56	55	2	
Derivative Liability	4	6	(2)	
Accrued Taxes	97	65	32	Increase is primarily due to accrual of 2016 extension settlement.
Regulatory Liabilities Current	12	23	(12)	Decrease primarily related to ECR, DSM, and FAC.
Other Current Liabilities	243	237	6	
Total Current Liabilities	729	609	120	
Debt - Affiliated Company	528	573	(45)	
Debt [1]	4,793	4,827	(34)	
Total Debt	5,321	5,400	(79)	
Deferred Tax Liabilities	1,727	1,735	(8)	
Investment Tax Credit	132	131	1	
Accum Provision for Pension & Related Benefits	332	411	(78)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	372	360	12	
Regulatory Liabilities Non Current	902	871	30	
Derivative Liability	26	32	(6)	
Other Liabilities	188	199	(12)	
Total Deferred Credits and Other Liabilities	3,678	3,740	(61)	
Equity	4,645	4,773	(127)	
Total Liabilities and Equity	**$ 14,374**	**$ 14,521**	**$ (148)**	

[1] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

February 2017

($ Millions)

	2/28/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 8	$ 5	$ 3	
Accounts Receivable (Trade)	177	190	(14)	
Inventory	121	111	9	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	13	5	8	
Prepayments and other current assets	48	49	(0)	Primarily due to increase in accounts receivable from associated company related to federal income tax settlement.
Total Current Assets	367	360	6	
Property, Plant, and Equipment	5,008	5,047	(39)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	448	501	(54)	Primarily due to MTM adjustment of Swaps, a pension funded status adjustment due to change in discount rate, and ARO revaluation.
Goodwill	0	0	0	
Other Long-term Assets	16	21	(5)	
Total Assets	**$ 5,845**	**$ 5,937**	**$ (92)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 146	$ 152	$ (6)	
Dividends Payable to Affiliated Companies	87	25	62	In the budget dividends are calculated in the month declared and any excess dividends are not recognized until the subsequent month due to balancing within the budget system.
Customer Deposits	27	26	1	
Derivative Liability	4	6	(2)	
Accrued Taxes	76	33	43	Increase is primarily due to accrual of 2016 extension settlement.
Regulatory Liabilities Current	2	5	(2)	
Other Current Liabilities	93	97	(5)	
Total Current Liabilities	435	344	91	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	1,728	1,779	(51)	
Total Debt	1,728	1,779	(51)	
Deferred Tax Liabilities	972	973	(1)	
Investment Tax Credit	36	36	(0)	
Accum Provision for Pension & Related Benefits	51	76	(25)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	103	99	3	
Regulatory Liabilities Non Current	369	358	11	
Derivative Liability	26	32	(6)	
Other Liabilities	86	92	(6)	
Total Deferred Credits and Other Liabilities	1,643	1,668	(24)	
Equity	2,039	2,146	(107)	
Total Liabilities and Equity	**$ 5,845**	**$ 5,937**	**$ (92)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

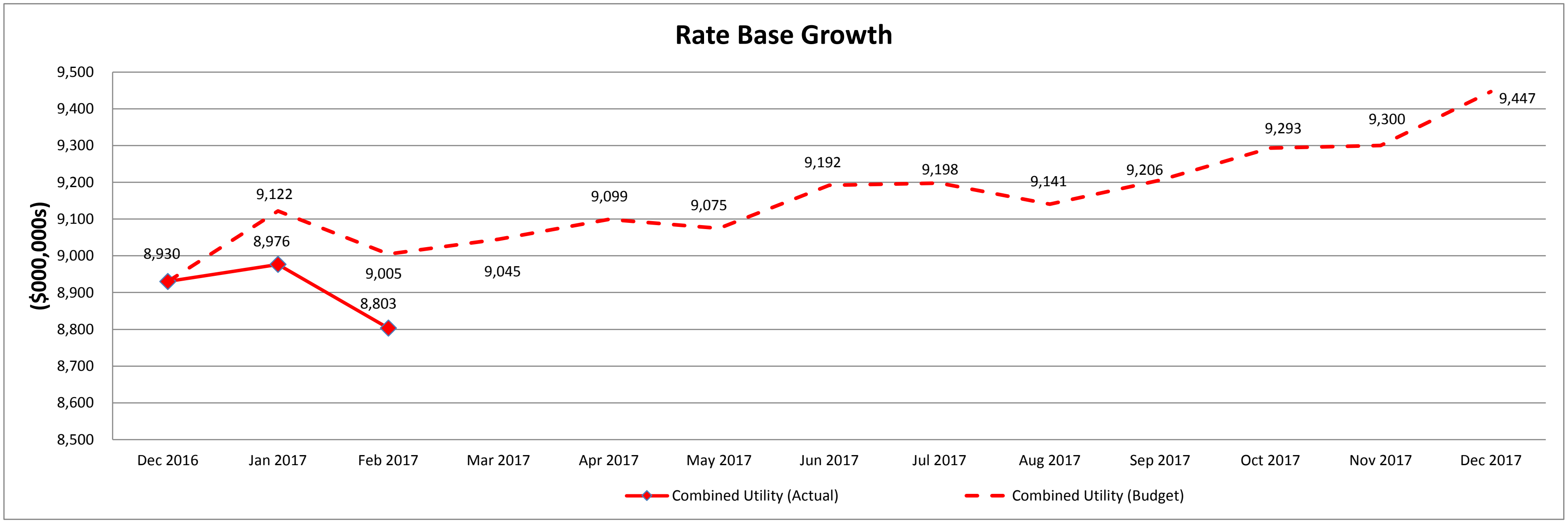
Balance Sheet - KU

February 2017

($ Millions)

	2/28/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 8	$ 18	$ (9)	
Accounts Receivable (Trade)	220	239	(19)	
Inventory	158	142	15	Higher inventory levels due to decreased fuel burn as a result of lower generation
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	11	16	(5)	
Prepayments and other current assets	22	19	3	
Total Current Assets	419	433	(14)	
Property, Plant, and Equipment	6,601	6,614	(13)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	376	405	(29)	
Goodwill	0	0	0	
Other Long-term Assets	58	58	1	
Total Assets	**$ 7,467**	**$ 7,522**	**$ (55)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 112	$ 114	$ (2)	
Dividends Payable to Affiliated Companies	70	40	30	In the budget dividends are calculated in the month declared and any excess dividends are not recognized until the subsequent month due to balancing within the budget system.
Customer Deposits	29	28	1	
Derivative Liability	0	0	0	
Accrued Taxes	47	42	5	
Regulatory Liabilities Current	9	18	(9)	
Other Current Liabilities	84	83	0	
Total Current Liabilities	351	325	26	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,343	2,325	18	
Total Debt	2,343	2,325	18	
Deferred Tax Liabilities	1,164	1,206	(42)	
Investment Tax Credit	95	95	1	
Accum Provision for Pension & Related Benefits	44	67	(22)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	269	261	8	
Regulatory Liabilities Non Current	459	437	21	
Derivative Liability	0	0	0	
Other Liabilities	49	53	(4)	
Total Deferred Credits and Other Liabilities	2,080	2,118	(38)	
Equity	2,693	2,754	(61)	
Total Liabilities and Equity	**$ 7,467**	**$ 7,522**	**$ (55)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.


Rate Base Growth
($000,000s)
9,500
9,400
9,300
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
8,930
9,122
8,976
9,005
8,803
9,045
9,099
9,075
9,192
9,198
9,141
9,206
9,293
9,300
9,447
Dec 2016
Jan 2017
Feb 2017
Mar 2017
Apr 2017
May 2017
Jun 2017
Jul 2017
Aug 2017
Sep 2017
Oct 2017
Nov 2017
Dec 2017
Combined Utility (Actual)
Combined Utility (Budget)

Performance Report

March 2017

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Kentucky Regulated Dashboard — March 2017

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees[(1)]	1.06	1.47	1.03	0.91	1.35	1.12
Employee lost-time incidents	0	1	2	1	9	5
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,659	2,695	7,958	8,746	33,636	34,425
Utility EFOR	1.4%	5.0%	3.7%	5.0%	N/A	5.0%
Utility EAF	75.0%	75.4%	81.8%	86.2%	N/A	85.2%
Steam Fleet Commercial Availability	93.9%	93.0%	92.6%	93.0%	N/A	93.0%
Combined SAIFI	0.05	0.07	0.16	0.22	N/A	1.03
Combined SAIDI (minutes)	3.26	5.91	12.77	18.61	N/A	93.20
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	794	866	2,542	3,003	10,207	10,668
Commercial	609	603	1,836	1,898	7,820	7,882
Industrial	808	758	2,211	2,279	9,637	9,706
Municipals	144	151	434	489	1,790	1,846
Other	215	214	646	666	2,733	2,753
Off-System Sales	54	24	132	70	306	244
Total	2,624	2,616	7,801	8,405	32,494	33,098
Weather-Normalized Sales Growth			**TTM**			
Residential			0.55%			
Commercial			1.49%			
Industrial			-2.79%			
Municipal			-1.01%			
Other			-0.46%			
Total			-0.39%			

	Current Month		YTD		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$144	$149	$442	$476	$1,908	$1,948
Gas Margins	$19	$18	$64	$66	$180	$183
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$64	$75	$161	$185	$1,107	$1,107
O&M ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
O&M – Management View [(2)]	$71	$63	$181	$177	$728	$749
O&M – Total GAAP View [(3)]	$79	$72	$207	$203	$843	$864
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,459	3,607	3,459	3,607	3,583	3,591
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	2	0	N/A	3
NERC Possible Violations[(4)]	2	0	3	0	N/A	5

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
ROE[(5)]	9.7%	9.8%	9.8%

Variance Explanations

• Lower current month margins primarily due to lower sales volumes from warmer than average weather resulting in lower retail electric base energy of $4 million.

• Lower margins YTD primarily due to lower sales volumes from warmer than average weather resulting in lower retail electric base energy and demand revenue of $34 million.

• Higher current month O&M due to the timing of maintenance and outage expenses of $2 million, employee benefits and burden costs of $2m and higher allocated and indirect costs for the month of $4 million.

(1) Full year forecast amount shown represents target.

(2) Net of cost recovery mechanisms.

(3) Includes Management O&M, Variable Cost of Production and Mechanism operation and maintenance expenses

(4) The possible violation issues for YTD Actual is believed to be minimal risk.

(5) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Major Developments

• On April 19th, LKE filed an agreement signed by virtually all parties in the rate case proceeding, except AT&T and the Kentucky Cable Television Association (who had raised issues in the case related to pole attachments), which addressed substantially all issues in the case. This agreement is not expected to impact PPL's earnings projections. It provides for a 9.75 percent return on equity using the utilities' filed capital structure. Other adjustments from the utilities' filed position on the required revenue increase relate to the timing of cost recovery, such as depreciation rates. Under the terms of the agreement, the Companies agreed to withdraw their current request for a certificate of public convenience and necessity on its proposed full deployment of advanced meter systems and instead will establish a collaborative with interested parties in this proceeding to address their issues with LKE's proposal. The agreement does provide for approval of the utilities' distribution automation project and recovery of its proposed transmission modernization and steel service line replacement programs through LG&E's gas line tracker mechanism. The public hearing is scheduled to begin May 9th.

• During the 2017 Kentucky General Assembly, the Senate confirmed Governor Bevin's appointments of Michael J. Schmitt and Robert J. Cicero, as Chairman and Vice Chair, to the KPSC.

• For both Louisville and Lexington, March 2017 ranked as the seventh warmest March in the last 30 years. This follows the warmest February on record for these cities. The first quarter 2017 also ranked as the warmest first quarter in Lexington over the previous 30 years, and the second warmest in Louisville during the same period.

• KU has completed the Ghent refined coal transaction with Goldman Sachs. It replaces a one year operation agreement with Tinuum and allows KU to sell its coal to Goldman Sachs and repurchase it after the coal is treated. KU will also provide a site license and coal yard services. The transaction will save customers $9.8 million annually and over $43 million for the entire project.

Significant Future Events

• An Order from the KPSC in the rate case proceeding is expected on or around June 30, 2017, with new rates going into effect on July 1st of this year.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — March 2017

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 224	$ 232	$ (8)	Due primarily to lower sales volumes driven by mild weather.
Gas Revenues	36	40	(4)	
Total Revenues	260	272	(12)	
Cost of Sales:				
Fuel Electric Costs	61	65	3	
Gas Supply Expenses	16	20	4	
Purchased Power	6	5	(1)	
Other Electric Cost of Production	3	3	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	5	5	(0)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	6	0	
Total Cost of Sales	98	105	7	
Gross Margin:				
Electric Margin	144	149	(5)	See explanation above.
Gas Margin	19	18	1	
Total Gross Margin	163	167	(5)	
Operating Expenses:				
O&M	71	63	(8)	Higher O&M due to the timing of maintenance and outage expenses, employee benefits and burden costs, and higher allocated and indirect costs for the month.
Depreciation & Amortization	30	30	0	
Taxes, Other than Income	5	5	0	
Total Operating Expenses	106	98	(7)	
Equity in Earnings	0	0	0	
Other income (expense)	(1)	(1)	(0)	
EBIT	56	68	(12)	
Interest Expense	18	18	0	
Income from Ongoing Operations before income taxes	38	50	(12)	
Income Tax Expense	14	19	4	
Net Income (loss) from ongoing operations	**24**	**31**	**(8)**	
Special Item - EEI	(1)	0	(1)	
Discontinued Operations	0	0	0	
Net Income (loss)	$ 23	$ 31	$ (8)	
KY Regulated Financing Costs	(3)	$ (3)	(0)	
KY Regulated Net Income	$ 21	$ 29	$ (8)	
Earnings Per Share - Ongoing	$ 0.03	$ 0.04	$ (0.01)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — March 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 689	$ 742	$ (54)	Due primarily to lower sales volumes driven by mild weather.
Gas Revenues	121	144	(23)	Due primarily to lower sales volumes driven by mild weather.
Total Revenues	810	886	(76)	
Cost of Sales:				
Fuel Electric Costs	191	211	20	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	53	74	21	Due primarily to lower gas usage as a result of mild weather.
Purchased Power	15	15	(1)	
Other Electric Cost of Production	9	10	2	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	18	16	(2)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	17	18	1	
Total Cost of Sales	303	344	41	
Gross Margin:				
Electric Margin	442	476	(34)	See explanations above.
Gas Margin	64	66	(2)	
Total Gross Margin	507	542	(35)	
Operating Expenses:				
O&M	181	177	(4)	
Depreciation & Amortization	89	90	1	
Taxes, Other than Income	14	15	1	
Total Operating Expenses	284	282	(2)	
Other income (expense)	(4)	(3)	(1)	
EBIT	219	258	(38)	
Interest Expense	53	53	0	
Income from Ongoing Operations before income taxes	167	205	(38)	
Income Tax Expense	63	78	15	
Net Income (loss) from ongoing operations	**103**	**126**	**(23)**	
Special Item - EEI	(1)	0	(1)	
Discontinued Operations	0	0	0	
Net Income (loss)	$ 103	$ 126	$ (23)	
KY Regulated Financing Costs	(8)	(7)	(0)	
KY Regulated Net Income	95	$ 119	$ (23)	
Earnings Per Share - Ongoing	$ 0.14	$ 0.17	$ (0.03)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E

March 2017

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 271	$ 278	$ (7)	Due primarily to lower sales volumes driven by mild weather.
Gas Revenues	121	144	(23)	Due primarily to lower sales volumes driven by mild weather.
Total Revenues	392	422	(30)	
Cost of Sales:				
Fuel Electric Costs	82	82	(1)	
Gas Supply Expenses	53	74	21	Due primarily to lower gas usage as a result of mild weather.
Purchased Power	11	11	0	
Other Electric Cost of Production	3	4	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	7	6	(0)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	10	10	0	
Total Cost of Sales	166	187	21	
Gross Margin:				
Electric Margin	161	168	(7)	See explanations above.
Gas Margin	64	66	(2)	
Total Gross Margin	226	235	(9)	
Operating Expenses:				
O&M	77	79	2	
Depreciation & Amortization	36	36	1	
Taxes, Other than Income	7	7	1	
Total Operating Expenses	120	123	3	
Other income (expense)	(2)	(2)	(0)	
EBIT	104	110	(6)	
Interest Expense	17	17	0	
Income from Ongoing Operations before income taxes	87	93	(6)	
Income Tax Expense	33	36	2	
Net Income (loss) from ongoing operations	**$ 54**	**$ 57**	**$ (4)**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU — March 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 437	$ 484	$ (46)	Due primarily to lower sales volumes driven by mild weather.
Gas Revenues	0	0	0	
Total Revenues	437	484	(46)	
Cost of Sales:				
Fuel Electric Costs	111	131	20	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	0	0	0	
Purchased Power	21	21	(0)	
Other Electric Cost of Production	5	7	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	11	10	(1)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	8	8	0	
Total Cost of Sales	156	176	20	
Gross Margin:				
Electric Margin	281	308	(27)	See explanations above.
Gas Margin	0	0	0	
Total Gross Margin	281	308	(27)	
Operating Expenses:				
O&M	93	93	(0)	
Depreciation & Amortization	53	53	1	
Taxes, Other than Income	7	7	0	
Total Operating Expenses	153	154	1	
Other income (expense)	(1)	(1)	(0)	
EBIT	127	153	(26)	
Interest Expense	24	24	(0)	
Income from Ongoing Operations before income taxes	103	129	(26)	
Income Tax Expense	39	49	10	
Net Income (loss) from ongoing operations	**$ 64**	**$ 80**	**$ (16)**	

Note: Schedules may not sum due to rounding.

Income Statement: Forecast vs. Budget - LKE Consolidated — March 2017

($ Millions)

	Full Year			
	Q1 Forecast	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 2,956	$ 3,017	$ (61)	Due primarily to lower sales volumes driven by unfavorable weather during the first quarter.
Gas Revenues	306	329	(23)	Due primarily to lower sales volumes driven by unfavorable weather during the first quarter.
Total Revenues	3,262	3,346	(85)	
Cost of Sales:				
Fuel Electric Costs	793	813	21	Primarily due to decreased generation as a result of unfavorable weather during the first quarter.
Gas Supply Expenses	114	135	21	Due primarily to lower gas usage as a result of unfavorable weather during the first quarter.
Purchased Power	60	60	(1)	
Other Electric Cost of Production	40	41		
Mechanism - ECR, DSM & GLT - Operation and Maintenance	75	74		
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	91	93	2	
Total Cost of Sales	1,173	1,216	43	
Gross Margin:				
Electric Margin	1,908	1,948	(40)	See explanations above.
Gas Margin	180	183	(2)	
Total Gross Margin	2,088	2,130	(42)	
Operating Expenses:				
O&M	728	749	21	Lower O&M primarily due to cost savings across all business units for the year partially offset by increased indirect charges from PPL.
Depreciation & Amortization	393	395	2	
Taxes, Other than Income	60	61	1	
Total Operating Expenses	1,182	1,205	23	
Other income (expense)	(8)	(8)	(0)	
EBIT	898	917	(19)	
Interest Expense	219	217	(2)	
Income from Ongoing Operations before income taxes	679	700	(21)	
Income Tax Expense	258	267	8	
Net Income (loss) from ongoing operations	**421**	**433**	**$ (13)**	
Special Item - EEI	(1)	0	(1)	
Discontinued Operations	1	(0)	1	
Net Income (loss)	$ 421	$ 433	$ (12)	
KY Regulated Financing Costs	(30)	(30)	(0)	
KY Regulated Net Income	$ 391	$ 403	$ (12)	
Earnings Per Share - Ongoing	$ 0.56	$ 0.58	$ (0.02)	

Note: Schedules may not sum due to rounding.

O&M **March 2017**

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	20	18	(1)	0	(0)	(2)	1	(1)
Project Engineering	0	0	(0)	0	-	(0)	(0)	0
Transmission	3	3	0	(0)	(0)	0	0	(0)
Energy Supply and Analysis	1	1	0	(0)	-	0	0	0
Generation Services	1	1	0	(0)	0	0	(0)	0
Electric Distribution	6	6	0	(0)	1	(1)	0	0
Gas Distribution and AMS2	3	3	(0)	0	(0)	(0)	(0)	(0)
Safety and Technical Training	0	0	(0)	(0)	(0)	(0)	(0)	0
Customer Services	8	8	0	(0)	0	0	(0)	0
Senior VP Operations	**43**	**41**	**(2)**	**0**	**0**	**(2)**	**1**	**(0)**
Audit Services	0	0	(0)	(0)	-	-	(0)	0
Controller	1	1	(0)	(0)	-	0	0	(0)
Supply Chain	0	0	0	0	-	0	0	0
Treasurer	2	2	(0)	(0)	-	(0)	(0)	(0)
State Regulation and Rates	0	0	0	(0)	-	0	0	0
Other	0	0	0	0	-	(0)	0	0
Chief Financial Officer	**4**	**4**	**(0)**	**(0)**	**-**	**0**	**0**	**(0)**
General Counsel	**3**	**3**	**0**	**0**	**0**	**(0)**	**(0)**	**0**
Human Resources	**1**	**1**	**0**	**0**	**-**	**0**	**0**	**0**
Information Technology	**4**	**5**	**0**	**0**	**0**	**0**	**(0)**	**0**
Corporate	**16**	**10**	**(7)**	**(5)**	**0**	**0**	**(0)**	**(2)**
Enterprise Security	**0**	**0**	**0**	**0**	**-**	**-**	**0**	**(0)**
O&M Total MTD	**71**	**63**	**(8)**	**(5)**	**0**	**(2)**	**1**	**(2)**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	48	46	(2)	1	0	(2)	0	(1)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	7	8	1	(0)	0	1	(0)	(0)
Energy Supply and Analysis	2	2	0	(0)	-	0	0	0
Generation Services	3	3	(0)	(0)	0	0	(0)	0
Electric Distribution	16	18	2	0	2	(1)	0	0
Gas Distribution and AMS	9	8	(0)	0	(0)	(0)	0	(0)
Safety and Technical Training	1	1	(0)	(0)	(0)	(0)	(0)	0
Customer Services	23	24	1	(0)	1	0	0	1
SVP Operations	**110**	**112**	**1**	**1**	**3**	**(2)**	**1**	**(0)**
Audit Services	0	0	0	0	-	(0)	(0)	0
Controller	2	2	(0)	(0)	-	0	0	(0)
Supply Chain	1	1	0	0	(0)	(0)	(0)	0
Treasurer	6	6	(0)	(0)	-	0	(0)	(0)
State Regulation and Rates	1	1	(0)	(0)	-	0	(0)	0
Other	0	1	0	0	-	0	0	(0)
Chief Financial Officer	**11**	**11**	**(0)**	**(0)**	**(0)**	**0**	**(0)**	**(0)**
General Counsel	**7**	**7**	**0**	**0**	**0**	**(0)**	**(0)**	**0**
Human Resources	**2**	**2**	**0**	**0**	**-**	**(0)**	**(0)**	**0**
Information Technology	**13**	**14**	**1**	**0**	**(0)**	**0**	**(0)**	**0**
Corporate	**37**	**30**	**(6)**	**(5)**	**0**	**0**	**(0)**	**(2)**
Enterprise Security	**1**	**1**	**0**	**(0)**	**-**	**-**	**0**	**0**
O&M Total YTD	**181**	**177**	**(4)**	**(4)**	**3**	**(2)**	**0**	**(2)**

	Full Year							
	Forecast	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	205	205	(0)	0	0	0	0	(1)
Project Engineering	1	1	0	0	-	(0)	(0)	0
Transmission	34	34	0	(0)	(0)	1	(0)	(0)
Energy Supply and Analysis	13	13	0	0	-	(0)	0	0
Generation Services	11	11	(0)	(0)	0	(0)	(0)	0
Electric Distribution	73	74	1	(0)	2	(1)	0	0
Gas Distribution and AMS	39	38	(1)	0	(1)	0	(0)	(0)
Safety and Technical Training	5	5	(0)	(0)	(0)	(0)	0	0
Customer Services	99	99	0	0	1	(0)	(0)	0
SVP Operations	**480**	**482**	**1**	**1**	**2**	**(0)**	**(0)**	**(1)**
Audit Services	2	2	0	0	-	-	(0)	0
Controller	9	9	0	0	-	0	0	(0)
Supply Chain	4	4	0	(0)	(0)	(0)	0	0
Treasurer	24	25	1	(0)	-	(0)	(0)	1
State Regulation and Rates	4	4	0	(0)	-	0	(0)	(0)
Other	2	2	0	0	-	0	0	(0)
Chief Financial Officer	**45**	**46**	**1**	**0**	**(0)**	**0**	**(0)**	**1**
General Counsel	**32**	**32**	**(0)**	**0**	**0**	**(0)**	**(0)**	**0**
Human Resources	**7**	**7**	**0**	**0**	**-**	**0**	**(0)**	**0**
Information Technology	**57**	**56**	**(0)**	**(0)**	**(0)**	**0**	**(0)**	**(0)**
Corporate	**104**	**122**	**18**	**(4)**	**0**	**0**	**(0)**	**22**
Enterprise Security	**3**	**3**	**0**	**0**	**-**	**-**	**0**	**0**
O&M Total YTD	**728**	**749**	**21**	**(3)**	**2**	**(0)**	**(0)**	**[illegible]**

Case Nos. 2018-00294 and 2018-00295
Attachment to Filing Requirement
807 KAR 5:001 Sec. 16(7)(o)
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Arbough

Financing Activities — March 2017

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB						
Beg Bal	$ 898.8	$ 898.8	$ -	$ 898.8	$ 898.8	$ -
End Bal	898.8	898.8	0.0	899.6	898.7	(0.9)
Ave Bal	**$ 898.8**	**$ 898.8**	**$ 0.0**	**$ 899.2**	**$ 898.7**	**$ (0.4)**
Interest Exp	**$ 3.3**	**$ 3.1**	**$ (0.2)**	**$ 12.6**	**$ 11.9**	**$ (0.7)**
Rate	**1.48%**	**1.37%**	**-0.11%**	**1.39%**	**1.31%**	**-0.08%**
FMB/Sr Nts/Loan with PPL						
Beg Bal	$ 4,210.0	$ 4,210.0	$ 0.0	$ 4,210.0	$ 4,210.0	$ 0.0
End Bal	4,210.0	4,210.0	0.0	4,529.4	4,608.5	79.1
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ 0.0**	**$ 4,369.7**	**$ 4,409.2**	**$ 39.53**
Interest Exp	**$ 45.8**	**$ 46.1**	**$ 0.3**	**$ 187.6**	**$ 187.7**	**$ 0.1**
Rate	**4.35%**	**4.38%**	**0.02%**	**4.23%**	**4.20%**	**-0.04%**
Short-term Debt						
Beg Bal	$ 348.1	$ 509.7	$ 161.6	$ 348.1	$ 509.7	$ 161.6
End Bal	325.1	480.6	155.5	517.7	530.2	12.5
Ave Bal (1)	**$ 336.6**	**$ 495.1**	**$ 158.6**	**$ 432.9**	**$ 520.0**	**$ 87.1**
Interest Exp	**$ 1.1**	**$ 1.4**	**$ 0.2**	**$ 8.9**	**$ 6.9**	**$ (2.0)**
Rate	**1.63%**	**1.12%**	**-0.51%**	**2.02%**	**1.31%**	**-0.71%**
Unamortized Debt Expense Bonds						
Beg Bal	$ (44.0)	$ (43.2)	$ 0.7	$ (44.0)	$ (43.2)	$ 0.7
End Bal	(43.1)	(41.9)	1.2	(41.4)	(42.0)	(0.6)
Ave Bal	**$ (43.5)**	**$ (42.6)**	**$ 1.0**	**$ (42.7)**	**$ (42.6)**	**$ 0.1**
Total End Bal	**$ 5,390.7**	**$ 5,547.5**	**$ 156.7**	**$ 5,905.2**	**$ 5,995.3**	**$ 90.1**
Total Average Bal	**$ 5,346.7**	**$ 5,561.4**	**$ 214.7**	**$ 5,659.1**	**$ 5,785.3**	**$ 126.2**
Total Expense Excl I/C (2)	**$ 52.8**	**$ 53.2**	**$ 0.4**	**$ 219.5**	**$ 217.2**	**$ (2.3)**
Rate	**3.92%**	**3.80%**	**-0.12%**	**3.80%**	**3.68%**	**-0.12%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use the average of the beginning and ending balances.
(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(3)	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 82		$ 218
LG&E	500	207		293
KU	598	36	$ 198	364
TOTAL	$ 1,398	$ 325	$ 198	$ 875

(3) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2017 Actual YTD	LKE 2017 Budget YTD	LG&E 2017 Actual YTD	LG&E 2017 Budget YTD	KU 2017 Actual YTD	KU 2017 Budget YTD
CFO pre-WC / Debt	19%	18%	26%	26%	24%	26%
CFO pre-WC + Interest / Interest	5.8	5.9	7.8	7.9	7.0	7.6
CFO pre-WC - Dividends / Debt	13%	14%	18%	21%	15%	16%
Debt to Capitalization[2]	47%	48%	38%	39%	38%	38%

Credit Metrics Moody's	LKE 2017 BP 2018	LKE 2017 BP 2019	LG&E 2017 BP 2018	LG&E 2017 BP 2019	KU 2017 BP 2018	KU 2017 BP 2019
CFO pre-WC / Debt	18%	18%	27%	29%	26%	26%
CFO pre-WC + Interest / Interest	6.0	5.7	8.5	8.7	7.8	7.6
CFO pre-WC - Dividends / Debt	11%	15%	25%	22%	20%	18%
Debt to Capitalization[2]	50%	49%	38%	36%	37%	37%

[1] Actuals represent a trailing 12 months.
[2] For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2016	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — March 2017

($ Millions)

	3/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 15	$ 105	$ (90)	Primarily due to LKE other excess cash from dividends in budget not used to pay down CEP Reserves.
Accounts Receivable (Trade)	375	414	(39)	
Inventory	256	242	13	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	23	21	2	
Prepayments and other current assets	44	33	11	Increases in prepayments, preliminary survey costs, and other transportation and engineering amounts.
Total Current Assets	713	816	(102)	
Property, Plant, and Equipment	11,636	11,701	(65)	
Intangible Assets	93	95	(2)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	828	911	(84)	
Goodwill	997	997	0	
Other Long-term Assets	77	81	(4)	
Total Assets	**$ 14,344**	**$ 14,602**	**$ (257)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 217	$ 222	$ (5)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	56	55	2	
Derivative Liability	4	6	(2)	
Accrued Taxes	37	43	(6)	
Regulatory Liabilities Current	16	23	(7)	
Other Current Liabilities	219	222	(3)	
Total Current Liabilities	549	570	(21)	
Debt - Affiliated Company	482	589	(107)	Used tax settlements and dividends from utilities to pay down CEP reserves.
Debt [(1)]	4,909	4,959	(50)	
Total Debt	5,391	5,547	(157)	
Deferred Tax Liabilities	1,786	1,781	5	
Investment Tax Credit	131	131	1	
Accum Provision for Pension & Related Benefits	332	411	(78)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	374	362	12	
Regulatory Liabilities Non Current	897	867	30	
Derivative Liability	25	32	(7)	
Other Liabilities	188	197	(8)	
Total Deferred Credits and Other Liabilities	3,734	3,780	(46)	
Equity	4,670	4,705	(35)	
Total Liabilities and Equity	**$ 14,344**	**$ 14,602**	**$ (257)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E — March 2017

($ Millions)

	3/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 4	$ 5	$ (1)	
Accounts Receivable (Trade)	166	182	(17)	
Inventory	110	103	7	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	12	4	8	
Prepayments and other current assets	48	48	0	
Total Current Assets	340	343	(3)	
Property, Plant, and Equipment	5,018	5,066	(48)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	446	501	(54)	Primarily due to MTM adjustment of Swaps, a pension funded status adjustment due to change in discount rate, and ARO revaluation.
Goodwill	0	0	0	
Other Long-term Assets	16	21	(5)	
Total Assets	**$ 5,827**	**$ 5,937**	**$ (110)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 137	$ 152	$ (15)	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	27	26	1	
Derivative Liability	4	6	(2)	
Accrued Taxes	12	14	(2)	
Regulatory Liabilities Current	5	5	1	
Other Current Liabilities	78	95	(16)	Primarily due to timing of cash payments & ARO reclassification from current to long term.
Total Current Liabilities	264	297	(33)	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	1,825	1,849	(24)	
Total Debt	1,825	1,849	(24)	
Deferred Tax Liabilities	1,006	1,004	2	
Investment Tax Credit	36	36	(0)	
Accum Provision for Pension & Related Benefits	50	76	(25)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	114	100	14	Primarily due to the reclassification of ARO from current to long term.
Regulatory Liabilities Non Current	368	355	13	
Derivative Liability	25	32	(7)	
Other Liabilities	85	91	(6)	
Total Deferred Credits and Other Liabilities	1,685	1,694	(9)	
Equity	2,053	2,097	(44)	
Total Liabilities and Equity	**$ 5,827**	**$ 5,937**	**$ (110)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

Balance Sheet - KU

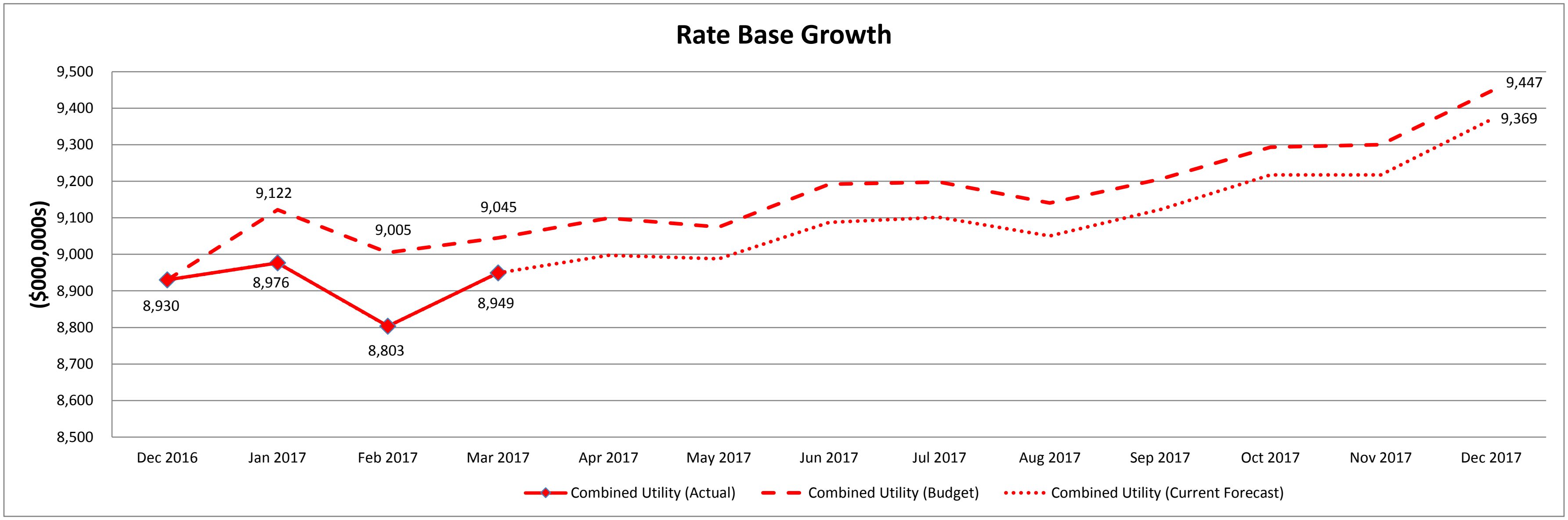
March 2017

($ Millions)

	3/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 7	$ 5	$ 2	
Accounts Receivable (Trade)	209	231	(22)	Due primarily to lower billed sales driven by mild weather.
Inventory	146	139	7	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	11	17	(5)	
Prepayments and other current assets	22	17	5	
Total Current Assets	394	409	(14)	
Property, Plant, and Equipment	6,610	6,627	(17)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	378	409	(31)	
Goodwill	0	0	0	
Other Long-term Assets	59	58	1	
Total Assets	**$ 7,454**	**$ 7,515**	**$ (61)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 126	$ 114	$ 12	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	29	28	1	
Derivative Liability	0	0	0	
Accrued Taxes	11	18	(7)	
Regulatory Liabilities Current	11	18	(7)	
Other Current Liabilities	94	83	11	Primarily due to timing of cash payments & ARO reclassification from long term to current.
Total Current Liabilities	271	260	11	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,361	2,387	(26)	
Total Debt	2,361	2,387	(26)	
Deferred Tax Liabilities	1,208	1,244	(37)	
Investment Tax Credit	95	95	1	
Accum Provision for Pension & Related Benefits	44	67	(22)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	260	262	(2)	
Regulatory Liabilities Non Current	455	436	19	
Derivative Liability	0	0	0	
Other Liabilities	49	52	(2)	
Total Deferred Credits and Other Liabilities	2,112	2,155	(44)	
Equity	2,710	2,713	(2)	
Total Liabilities and Equity	**$ 7,454**	**$ 7,515**	**$ (61)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

Case Nos. 2018-00294 and 2018-00295
Attachment to Filing Requirement
807 KAR 5:001 Sec. 16(7)(o)
Page 41 of 260
Arbough


Rate Base Growth
($000,000s)
9,500
9,400
9,300
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
Dec 2016
Jan 2017
Feb 2017
Mar 2017
Apr 2017
May 2017
Jun 2017
Jul 2017
Aug 2017
Sep 2017
Oct 2017
Nov 2017
Dec 2017
8,930
9,122
8,976
9,005
8,803
9,045
8,949
9,447
9,369
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Current Forecast)

KU and LG&E Combined
Reconciliation of Allowed Return to
Net Income Last Rate Case Regulatory Return
and ROE from Ongoing Operations

Allowed Return (1)		10.0%	
Adjustments (net tax):			
Change in capitalization - non mechanism	-0.1%		Growth in capitalization (rate base) between rate cases does not earn a return
Change in ROE from average mechanism rate base growth	0.0%		Mechanisms have a real-time return
Change in weighted cost of debt	-0.1%		Higher interest rates and borrowing
Change in margins	-0.7%		Lower revenue
Change in allowed expenses	0.6%		Lower revenue
		-0.3%	
Actual Regulated ROE		9.7%	

(1) Based on the most recent base rate filings with test years ending 6/30/16 KPSC, 12/31/15 FERC, 12/31/14 VA.

Performance Report

April 2017

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Kentucky Regulated Dashboard — April 2017

	Current Month		YTD		Full Year	
Safety	Actual	PY	Actual	PY	Forecast	PY
TCIR - Employees[1]	2.29	0.56	1.33	0.80	1.35	1.12
Employee lost-time incidents	0	0	2	1	8	5
Reliability	Actual	Budget	Actual	Budget	Forecast	Budget
Generation Volumes	2,377	2,369	10,334	11,116	33,644	34,425
Utility EFOR	6.2%	5.0%	4.3%	5.0%	N/A	5.0%
Utility EAF	71.3%	69.0%	79.2%	81.9%	N/A	85.2%
Steam Fleet Commercial Availability	92.7%	93.0%	92.6%	93.0%	N/A	93.0%
Combined SAIFI	0.07	0.11	0.23	0.32	N/A	1.03
Combined SAIDI (minutes)	7.16	8.14	19.93	26.75	N/A	93.20
GwH Sales	Actual	Budget	Actual	Budget	Forecast	Budget
Residential	591	635	3,132	3,637	10,163	10,668
Commercial	582	564	2,418	2,462	7,838	7,882
Industrial	772	754	2,983	3,033	9,655	9,706
Municipals	129	135	563	624	1,784	1,846
Other	209	204	855	870	2,738	2,753
Off-System Sales	27	14	160	84	320	244
Total	2,310	2,306	10,111	10,710	32,498	33,098
Weather-Normalized Sales Growth			TTM			
Residential			-0.20%			
Commercial			1.21%			
Industrial			-2.98%			
Municipal			-1.40%			
Other			-0.32%			
Total			-0.76%			

	Current Month		YTD		Full Year	
Margins ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Electric Margins	$135	$135	$577	$611	$1,908	$1,948
Gas Margins	$12	$13	$77	$79	$180	$183
Capital Expenditures ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Total	$59	$98	$220	$283	$1,107	$1,107
O&M ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
O&M – Management View [2]	$60	$66	$241	$242	$728	$749
O&M – Total GAAP View [3]	$68	$74	$275	$277	$843	$864
Head Count	Actual	Budget	Actual	Budget	Forecast	Budget
Full-time Employees	3,460	3,607	3,460	3,607	3,568	3,591
Other Metrics	Actual	PY	Actual	PY	Forecast	PY
Environmental Events	1	0	3	0	N/A	3
NERC Possible Violations[4]	0	0	3	0	N/A	5

	TTM	Full Year	
Financial Metrics	Actual	Forecast	Budget
ROE[5]	9.8%	9.8%	9.8%

Variance Explanations

Lower YTD margins primarily due to lower sales volumes from warmer than average weather resulting in lower retail electric base energy and demand revenue of $35 million.

Lower MTD O&M due to the timing of maintenance and outage expenses of $4m.

(1) Full year forecast amount shown represents target.

(2) Net of cost recovery mechanisms.

(3) Includes Management O&M, Variable Cost of Production and Mechanism operation and maintenance expenses

(4) The possible violation issues for YTD Actual is believed to be minimal risk.

(5) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Major Developments

A second Stipulation and Recommendation was filed with the KPSC in the 2016 rate case resulting in the resolution of all issues with all parties in the case. LG&E and KU are preparing for the hearing in the case which will begin May 9th. An Order from the KPSC is still expected on or around June 30, 2017, with new rates going into effect on July 1st of this year.

The Company continues its outstanding safety performance with a number of recent milestones and awards:
- Cane Run and Paddy’s Run employees are celebrating more than one year without a recordable injury and received the Governor’s Safety and Health Award in May.
- The Central Service Shop team, a combination of LG&E and PIC (a generation-services contractor) employees who maintain and repair plant equipment and parts at Riverport, recently completed more than 16 years without a lost-time incident and 175,000 hours without a recordable incident.
- Ohio Falls employees completed more than two years without a recordable injury and 10,000 hours without a lost-time incident.
- E.W. Brown employees celebrated a year in March without a recordable injury.
- LG&E was recognized by the American Gas Association with a Safety Achievement Award by experiencing the lowest incident rate for the number of days away from work, restricted or transferred (DART) among companies of its size and type.

LG&E and KU, along with IBEW Local 2100 and the LG&E and KU Foundation, were recognized for their fundraising efforts during Metro United Way’s 2016 campaign. The Company continued its trend of raising over $1 million for the campaign.

Significant Future Events

See rate case procedural schedule.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — April 2017

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 206	$ 208	$ (1)	
Gas Revenues	20	24	(4)	
Total Revenues	227	232	(5)	
Cost of Sales:				
Fuel Electric Costs	55	55	(0)	
Gas Supply Expenses	7	10	3	
Purchased Power	4	5	1	
Other Electric Cost of Production	3	3	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	5	5	0	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	6	0	
Total Cost of Sales	79	85	5	
Gross Margin:				
Electric Margin	135	135	0	
Gas Margin	12	13	(0)	
Total Gross Margin	147	147	0	
Operating Expenses:				
O&M	60	66	6	Lower O&M primarily due to the timing of maintenance and outage expenses
Depreciation & Amortization	30	30	0	
Taxes, Other than Income	5	5	0	
Total Operating Expenses	95	101	6	
Equity in Earnings	0	0	0	
Other income (expense)	(0)	(1)	0	
EBIT	52	46	6	
Interest Expense	18	18	0	
Income from Ongoing Operations before income taxes	34	28	6	
Income Tax Expense	13	11	(3)	
Net Income (loss) from ongoing operations	**21**	**17**	**4**	
Special Item - EEI	0	0	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 21	$ 17	$ 4	
KY Regulated Financing Costs	(3)	$ (2)	(0)	
KY Regulated Net Income	$ 19	$ 15	$ 4	
Earnings Per Share - Ongoing	$ 0.03	$ 0.02	$ 0.01	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — April 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 895	$ 950	$ (55)	Due primarily to lower sales volumes driven by mild weather in Q1.
Gas Revenues	141	168	(27)	Due primarily to lower sales volumes driven by mild weather in Q1.
Total Revenues	1,037	1,118	(82)	
Cost of Sales:				
Fuel Electric Costs	246	266	20	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	60	84	24	Due primarily to lower gas usage as a result of mild weather.
Purchased Power	19	20	1	
Other Electric Cost of Production	11	13	2	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	22	21	(1)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	23	24	1	
Total Cost of Sales	382	429	46	
Gross Margin:				
Electric Margin	577	611	(33)	See explanations above.
Gas Margin	77	79	(2)	
Total Gross Margin	654	689	(35)	
Operating Expenses:				
O&M	241	242	1	
Depreciation & Amortization	119	120	2	
Taxes, Other than Income	19	20	1	
Total Operating Expenses	379	382	4	
Other income (expense)	(4)	(4)	(0)	
EBIT	271	303	(32)	
Interest Expense	71	71	0	
Income from Ongoing Operations before income taxes	201	232	(32)	
Income Tax Expense	76	89	12	
Net Income (loss) from ongoing operations	**125**	**144**	**(19)**	
Special Item - EEI	(1)	0	(1)	
Discontinued Operations	0	0	0	
Net Income (loss)	$ 124	$ 144	$ (20)	
KY Regulated Financing Costs	(10)	(10)	(0)	
KY Regulated Net Income	114	$ 134	$ (20)	
Earnings Per Share - Ongoing	$ 0.17	$ 0.19	$ (0.03)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E

April 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 352	$ 359	$ (7)	Due primarily to lower sales volumes driven by mild weather in Q1.
Gas Revenues	141	168	(27)	Due primarily to lower sales volumes driven by mild weather in Q1.
Total Revenues	494	527	(34)	
Cost of Sales:				
Fuel Electric Costs	102	101	(2)	
Gas Supply Expenses	60	84	24	Due primarily to lower gas usage as a result of mild weather.
Purchased Power	15	17	2	
Other Electric Cost of Production	4	5	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	8	8	(0)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	13	13	1	
Total Cost of Sales	203	229	26	
Gross Margin:				
Electric Margin	214	220	(6)	See explanations above.
Gas Margin	77	79	(2)	
Total Gross Margin	291	299	(8)	
Operating Expenses:				
O&M	106	109	2	
Depreciation & Amortization	48	49	1	
Taxes, Other than Income	9	10	1	
Total Operating Expenses	164	167	4	
Other income (expense)	(2)	(2)	(0)	
EBIT	125	130	(5)	
Interest Expense	23	23	0	
Income from Ongoing Operations before income taxes	102	107	(5)	
Income Tax Expense	39	41	2	
Net Income (loss) from ongoing operations	**$ 63**	**$ 66**	**$ (3)**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU — April 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 564	$ 613	$ (49)	Due primarily to lower sales volumes driven by mild weather in Q1.
Gas Revenues	0	0	0	
Total Revenues	564	613	(49)	
Cost of Sales:				
Fuel Electric Costs	146	167	21	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	0	0	0	
Purchased Power	23	23	0	
Other Electric Cost of Production	7	9	2	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	14	13	(1)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	10	11	0	
Total Cost of Sales	201	223	22	
Gross Margin:				
Electric Margin	363	391	(27)	See explanations above.
Gas Margin	0	0	0	
Total Gross Margin	363	391	(27)	
Operating Expenses:				
O&M	122	127	5	Lower O&M primarily due to timing of plant maintenance, lower storm restoration and vegetation management.
Depreciation & Amortization	71	71	1	
Taxes, Other than Income	10	10	0	
Total Operating Expenses	202	209	6	
Other income (expense)	(2)	(2)	0	
EBIT	160	180	(21)	
Interest Expense	32	32	(0)	
Income from Ongoing Operations before income taxes	128	149	(21)	
Income Tax Expense	48	57	8	
Net Income (loss) from ongoing operations	**$ 79**	**$ 92**	**$ (13)**	

Note: Schedules may not sum due to rounding.

O&M								April 2017

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	20	25	5	0	(0)	1	3	0
Project Engineering	0	0	0	0	-	(0)	0	0
Transmission	2	3	0	0	0	0	(0)	0
Energy Supply and Analysis	1	1	(0)	(0)	-	(0)	0	(0)
Electric Distribution	6	6	0	0	0	(0)	0	0
Gas Distribution and AMS2	3	3	(0)	(0)	(0)	0	(0)	(0)
Safety and Technical Training	0	0	0	0	(0)	0	0	0
Customer Services	7	7	0	(0)	0	0	(0)	(0)
Senior VP Operations	**40**	**45**	**5**	**0**	**0**	**2**	**3**	**0**
Audit Services	0	0	0	(0)	-	0	0	0
Controller	1	1	0	(0)	(0)	0	0	0
Supply Chain	0	0	0	0	(0)	0	0	0
Treasurer	2	2	0	0	-	-	0	0
State Regulation and Rates	0	0	(0)	(0)	-	0	(0)	0
Other	0	0	(0)	(0)	-	0	0	(0)
Chief Financial Officer	**4**	**4**	**0**	**(0)**	**(0)**	**0**	**(0)**	**0**
General Counsel	**3**	**2**	**(1)**	**0**	**(0)**	**(0)**	**(0)**	**0**
Human Resources	**0**	**1**	**0**	**0**	**(0)**	**0**	**(0)**	**0**
Information Technology	**4**	**4**	**(0)**	**(0)**	**0**	**0**	**0**	**0**
Corporate	**9**	**10**	**1**	**1**	**0**	**0**	**(0)**	**(0)**
Enterprise Security	**0**	**0**	**0**	**(0)**	**-**	**-**	**0**	**0**
O&M Total MTD	**60**	**66**	**6**	**1**	**0**	**1**	**3**	**1**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	71	74	3	1	(0)	(1)	3	(1)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	9	11	1	(0)	0	1	(0)	0
Energy Supply and Analysis	3	3	(0)	(0)	-	0	0	0
Electric Distribution	22	24	2	0	3	(1)	0	0
Gas Distribution and AMS	12	11	(1)	0	(0)	0	(0)	(0)
Safety and Technical Training	2	2	(0)	(0)	(0)	(0)	(0)	0
Customer Services	30	32	1	(0)	1	0	0	1
SVP Operations	**150**	**156**	**7**	**1**	**3**	**(0)**	**4**	**(0)**
Audit Services	1	1	0	0	-	0	0	0
Controller	3	3	(0)	(0)	(0)	0	0	(0)
Supply Chain	1	1	0	0	(0)	0	0	0
Treasurer	8	8	(0)	(0)	-	0	(0)	0
State Regulation and Rates	1	1	(0)	(0)	-	0	(0)	0
Other	1	1	0	0	-	0	0	(0)
Chief Financial Officer	**15**	**15**	**(0)**	**(0)**	**(0)**	**0**	**(0)**	**0**
General Counsel	**10**	**10**	**(0)**	**0**	**0**	**(1)**	**(0)**	**1**
Human Resources	**2**	**2**	**0**	**0**	**(0)**	**0**	**(0)**	**0**
Information Technology	**17**	**18**	**1**	**(0)**	**0**	**0**	**(0)**	**0**
Corporate	**46**	**40**	**(6)**	**(4)**	**0**	**0**	**(0)**	**(2)**
Enterprise Security	**1**	**1**	**0**	**(0)**	**-**	**-**	**0**	**0**
O&M Total YTD	**241**	**242**	**1**	**(3)**	**3**	**(0)**	**3**	**(1)**

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Financing Activities — April 2017

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance
PCB			
Beg Bal	$ 898.8	$ 898.8	$ 0.0
End Bal	898.8	898.8	(0.0)
Ave Bal	**$ 898.8**	**$ 898.8**	**$ (0.0)**
Interest Exp	**$ 4.5**	**$ 4.1**	**$ (0.4)**
Rate	**1.50%**	**1.37%**	**-0.13%**
FMB/Sr Nts/Loan with PPL			
Beg Bal	$ 4,210.0	$ 4,210.0	$ 0.0
End Bal	4,210.0	4,210.0	0.0
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ 0.0**
Interest Exp	**$ 61.1**	**$ 61.4**	**$ 0.3**
Rate	**4.35%**	**4.38%**	**0.02%**
Short-term Debt			
Beg Bal	$ 348.1	$ 509.7	$ 161.6
End Bal	322.4	543.9	221.6
Ave Bal [(1)]	**$ 335.2**	**$ 526.8**	**$ 191.6**
Interest Exp	**$ 1.6**	**$ 1.9**	**$ 0.4**
Rate	**1.62%**	**1.10%**	**-0.52%**
Unamortized Debt Expense Bonds			
Beg Bal	$ (44.0)	$ (43.2)	$ 0.7
End Bal	(43.2)	(42.1)	1.1
Ave Bal	**$ (43.6)**	**$ (42.7)**	**$ 0.9**
Total End Bal	**$ 5,388.0**	**$ 5,610.6**	**$ 222.7**
Total Average Bal	**$ 5,357.5**	**$ 5,593.0**	**$ 235.5**
Total Expense Excl I/C [(2)]	**$ 70.5**	**$ 71.0**	**$ 0.5**
Rate	**3.92%**	**3.78%**	**-0.14%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use the average of the beginning and ending balances.
(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed[(3)]	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 113		$ 187
LG&E	500	183		317
KU	598	26	$ 198	374
TOTAL	$ 1,398	$ 322	$ 198	$ 878

(3) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2017 Actual YTD	 Budget YTD	LG&E 2017 Actual YTD	 Budget YTD	KU 2017 Actual YTD	 Budget YTD
CFO pre-WC / Debt	19%	18%	27%	25%	24%	26%
CFO pre-WC + Interest / Interest	5.8	5.8	7.9	7.8	7.0	7.5
CFO pre-WC - Dividends / Debt	13%	14%	19%	20%	15%	16%
Debt to Capitalization[2]	47%	48%	38%	39%	38%	38%

Credit Metrics Moody's	LKE 2017 BP 2018	 2019	LG&E 2017 BP 2018	 2019	KU 2017 BP 2018	 2019
CFO pre-WC / Debt	18%	18%	27%	29%	26%	26%
CFO pre-WC + Interest / Interest	6.0	5.7	8.5	8.7	7.8	7.6
CFO pre-WC - Dividends / Debt	11%	15%	25%	22%	20%	18%
Debt to Capitalization[2]	50%	49%	38%	36%	37%	37%

(1) Actuals represent a trailing 12 months.
(2) For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2016 Issuer	Senior Unsecured Moody's	Senior Secured Moody's	Commercial Paper Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated

April 2017

($ Millions)

	4/30/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 16	$ 106	$ (90)	Primarily due to LKE other excess cash from dividends in budget not used to pay down CEP Reserves.
Accounts Receivable (Trade)	373	380	(6)	
Inventory	263	245	18	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	27	22	6	
Prepayments and other current assets	51	42	9	
Total Current Assets	731	795	(63)	
Property, Plant, and Equipment	11,655	11,755	(100)	
Intangible Assets	92	94	(2)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	830	913	(83)	
Goodwill	997	997	0	
Other Long-term Assets	77	81	(4)	
Total Assets	**$ 14,383**	**$ 14,635**	**$ (252)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 231	$ 211	$ 20	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	56	55	2	
Derivative Liability	4	6	(2)	
Accrued Taxes	35	19	16	Budget assumed higher Q1 tax settlement to occur in April 2017.
Regulatory Liabilities Current	16	22	(6)	
Other Current Liabilities	224	213	11	
Total Current Liabilities	566	525	41	
Debt - Affiliated Company	513	619	(105)	Used tax settlements and dividends from utilities to pay down CEP reserves.
Debt [(1)]	4,875	4,992	(117)	
Total Debt	5,388	5,611	(223)	
Deferred Tax Liabilities	1,786	1,781	5	
Investment Tax Credit	131	131	1	
Accum Provision for Pension & Related Benefits	335	411	(76)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	374	362	12	
Regulatory Liabilities Non Current	897	864	33	
Derivative Liability	24	31	(7)	
Other Liabilities	190	197	(7)	
Total Deferred Credits and Other Liabilities	3,738	3,776	(39)	
Equity	4,691	4,723	(32)	
Total Liabilities and Equity	**$ 14,383**	**$ 14,635**	**$ (252)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

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Balance Sheet - LG&E

April 2017

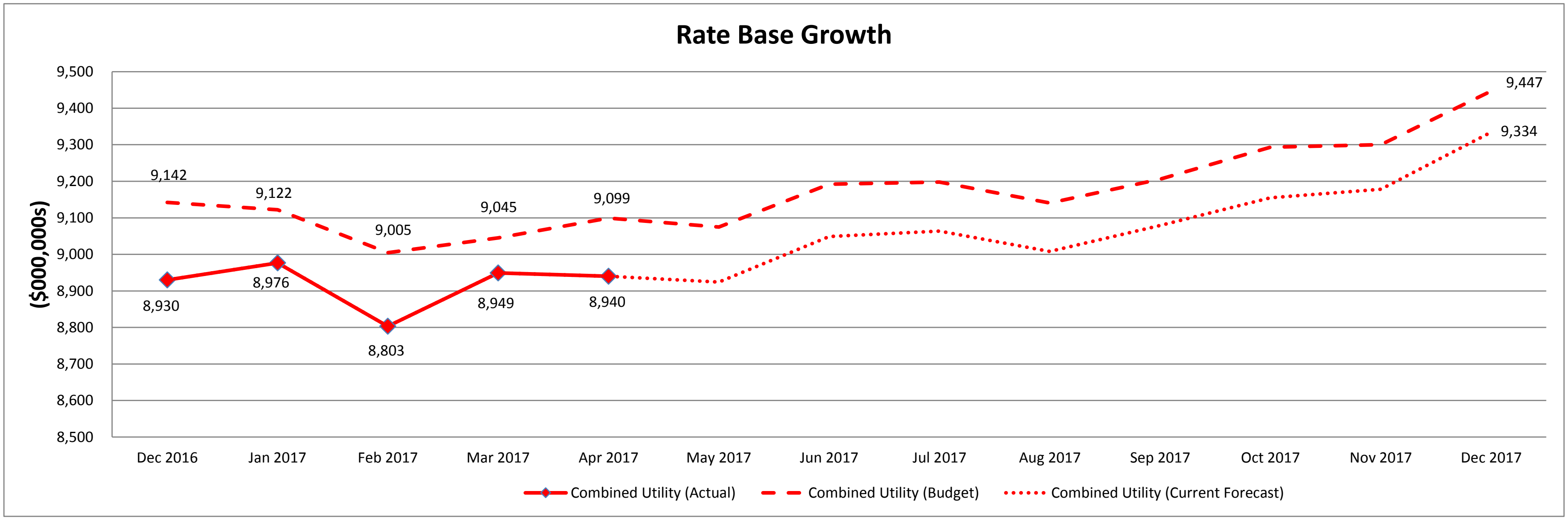
($ Millions)

	4/30/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 7	$ 5	$ 2	
Accounts Receivable (Trade)	156	165	(9)	
Inventory	112	104	8	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	14	6	8	
Prepayments and other current assets	42	47	(5)	
Total Current Assets	331	327	3	
Property, Plant, and Equipment	5,030	5,090	(60)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	447	499	(52)	Primarily due to MTM adjustment of Swaps, a pension funded status adjustment due to change in discount rate, and ARO revaluation.
Goodwill	0	0	0	
Other Long-term Assets	16	21	(5)	
Total Assets	**$ 5,829**	**$ 5,944**	**$ (114)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 141	$ 149	$ (7)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	27	26	1	
Derivative Liability	4	6	(2)	
Accrued Taxes	20	14	6	
Regulatory Liabilities Current	5	4	0	
Other Current Liabilities	84	89	(5)	
Total Current Liabilities	281	288	(7)	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	1,801	1,860	(60)	
Total Debt	1,801	1,860	(60)	
Deferred Tax Liabilities	1,006	1,004	2	
Investment Tax Credit	36	36	(0)	
Accum Provision for Pension & Related Benefits	51	75	(24)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	114	100	14	Primarily due to the reclassification of ARO from current to long term.
Regulatory Liabilities Non Current	367	353	15	
Derivative Liability	24	31	(7)	
Other Liabilities	87	92	(4)	
Total Deferred Credits and Other Liabilities	1,685	1,690	(5)	
Equity	2,063	2,105	(43)	
Total Liabilities and Equity	**$ 5,829**	**$ 5,944**	**$ (114)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

Balance Sheet - KU				**April 2017**
($ Millions)				
	4/30/2017	**YTD Budget**	**Variance**	**Comments**
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 9	$ 5	$ 4	
Accounts Receivable (Trade)	217	214	3	
Inventory	151	142	10	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	13	15	(2)	
Prepayments and other current assets	27	24	3	
Total Current Assets	418	400	17	
Property, Plant, and Equipment	6,617	6,656	(40)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	381	413	(32)	
Goodwill	0	0	0	
Other Long-term Assets	59	57	1	
Total Assets	**$ 7,487**	**$ 7,539**	**$ (53)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 137	$ 108	$ 28	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	29	28	1	
Derivative Liability	0	0	0	
Accrued Taxes	23	15	9	
Regulatory Liabilities Current	11	18	(6)	
Other Current Liabilities	95	81	14	Primarily due to ARO reclassification from long term to current.
Total Current Liabilities	296	250	46	
Debt - Affiliated Company	0	0	0	
Debt [1]	2,351	2,409	(57)	
Total Debt	2,351	2,409	(57)	
Deferred Tax Liabilities	1,208	1,244	(37)	
Investment Tax Credit	95	95	1	
Accum Provision for Pension & Related Benefits	45	67	(22)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	260	262	(2)	
Regulatory Liabilities Non Current	457	436	20	
Derivative Liability	0	0	0	
Other Liabilities	49	52	(3)	
Total Deferred Credits and Other Liabilities	2,114	2,156	(42)	
Equity	2,726	2,725	1	
Total Liabilities and Equity	**$ 7,487**	**$ 7,539**	**$ (53)**	

[1] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.


Rate Base Growth
9,500
9,400
9,300
9,200
9,100
9,000
8,900
8,800
8,700
8,600
8,500
($000,000s)
9,142
9,122
9,005
9,045
9,099
9,447
9,334
8,930
8,976
8,803
8,949
8,940
Dec 2016
Jan 2017
Feb 2017
Mar 2017
Apr 2017
May 2017
Jun 2017
Jul 2017
Aug 2017
Sep 2017
Oct 2017
Nov 2017
Dec 2017
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Current Forecast)

Performance Report

May 2017

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Kentucky Regulated Dashboard — May 2017

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees[1]	1.09	1.11	1.28	0.86	1.35	1.12
Employee lost-time incidents	0	0	2	1	7	5
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,683	2,718	13,017	13,833	33,609	34,425
Utility EFOR	2.7%	5.0%	3.9%	5.0%	N/A	5.0%
Utility EAF	88.5%	92.5%	81.1%	84.1%	N/A	85.2%
Steam Fleet Commercial Availability	96.8%	93.0%	93.4%	93.0%	N/A	93.0%
Combined SAIFI	0.08	0.10	0.31	0.43	N/A	1.03
Combined SAIDI (minutes)	8.12	9.25	28.06	36.00	N/A	93.20
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	749	710	3,881	4,348	10,201	10,668
Commercial	646	650	3,065	3,113	7,820	7,882
Industrial	799	858	3,782	3,891	9,610	9,706
Municipals	139	138	701	762	1,785	1,846
Other	227	231	1,081	1,102	2,733	2,753
Off-System Sales	56	34	215	117	341	244
Total	2,615	2,622	12,726	13,332	32,491	33,098
Weather-Normalized Sales Growth			**TTM**			
Residential			0.26%			
Commercial			1.52%			
Industrial			-2.30%			
Municipal			-1.40%			
Other			-0.31%			
Total			-0.33%			

	Current Month		YTD		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins[2]	$144	$145	$722	$756	$1,895	$1,948
Gas Margins	$10	$11	$87	$89	$180	$183
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total[2]	$64	$91	$284	$374	$1,069	$1,107
O&M ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
O&M – Management View[2] [3]	$56	$61	$297	$303	$725	$749
O&M – GAAP View[2] [4]	$64	$69	$339	$346	$838	$864
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,469	3,603	3,469	3,603	3,567	3,591
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	3	0	N/A	3
NERC Possible Violations[5]	1	1	4	1	N/A	5

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
Utility ROE[6]	9.8%	9.9%	9.8%
Average Utility Capitalization ($ millions)	$8,878	$9,031	$9,174

Variance Explanations

Lower margins YTD primarily due to lower sales volumes from warmer than average weather resulting in lower retail electric base energy and demand revenue and lower gas margins.

Lower O&M MTD primarily driven by lower storm restoration, vegetation management, maintenance and outage expense, and labor due to lower overtime and vacancies.

Lower O&M YTD primarily driven by lower storm restoration, vegetation management, maintenance and outage expense, and labor due to lower overtime and vacancies, partially offset by higher allocated and indirect costs.

Major Developments

The formal hearing in the rate case proceeding was held on May 9 and 10 and was followed by the filing of responses to post-hearing data requests and briefs from LKE and certain intervenors. These milestones were consistent with the procedural schedule and completed the record in the case. An Order from the KPSC is still expected on or around June 30, 2017, with new rates going into effect on July 1st of this year.

The Company was honored recently for its workplace and wellness initiatives. LKE received the United States Defense Department's highest state-level award, the Employer Support of the Guard and Reserve Award, for providing support to employees serving in the Kentucky National Guard and Reserve. LKE was also recognized by the Worksite Wellness Council of Louisville for the second consecutive year as a Platinum Award Winner for its wellness programs, and was awarded the Health Champion Designation Award by the American Diabetes Association.

Significant Future Events

There are no significant future events to report at this time.

(1) Full year forecast amount shown represents target.
(2) Includes net impact of proposed settlement stipulation adjustments of deferred AMS Capital and O&M expense, lower depreciation expense and the offsetting revenue reduction included in margins.
(3) Net of cost recovery mechanisms and variable costs of production.
(4) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses
(5) The possible violation issues for YTD Actual is believed to be minimal risk.
(6) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — May 2017

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 226	$ 226	$ 0	
Gas Revenues	17	18	(1)	
Total Revenues	243	244	(1)	
Cost of Sales:				
Fuel Electric Costs	63	62	(0)	
Gas Supply Expenses	5	6	1	
Purchased Power	5	5	(1)	
Other Electric Cost of Production	3	3	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	6	5	(0)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	6	0	
Total Cost of Sales	88	88	(0)	
Gross Margin:				
Electric Margin	144	145	(1)	
Gas Margin	10	11	(0)	
Total Gross Margin	155	156	(1)	
Operating Expenses:				
O&M	56	61	5	Primarily driven by lower storm restoration, vegetation management, maintenance and outage expense, and labor due to lower overtime and vacancies.
Depreciation & Amortization	30	30	0	
Taxes, Other than Income	5	5	0	
Equity in Earnings	0	0	0	
Other income (expense)	(1)	(1)	(0)	
EBIT	63	60	4	
Interest Expense	18	18	0	
Income from Ongoing Operations before income taxes	46	42	4	
Income Tax Expense	18	16	(2)	
Net Income (loss) from ongoing operations	**28**	**26**	**2**	
Special Item - EEI	0	0	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 28	$ 26	$ 2	
KY Regulated Financing Costs	(3)	$ (3)	(0)	
KY Regulated Net Income	$ 26	$ 23	$ 2	
Earnings Per Share - Ongoing	$ 0.04	$ 0.03	$ 0.00	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — May 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,121	$ 1,176	$ (55)	Due primarily to lower sales volumes driven by mild weather in Q1.
Gas Revenues	158	186	(28)	Due primarily to lower sales volumes driven by mild weather in Q1.
Total Revenues	1,279	1,362	(83)	
Cost of Sales:				
Fuel Electric Costs	309	329	20	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	65	90	25	Due primarily to lower gas usage as a result of mild weather.
Purchased Power	24	24	(0)	
Other Electric Cost of Production	15	17	2	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	28	26	(2)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	29	30	1	
Total Cost of Sales	470	516	46	
Gross Margin:				
Electric Margin	722	756	(34)	See explanations above.
Gas Margin	87	89	(2)	
Total Gross Margin	809	845	(37)	
Operating Expenses:				
O&M	297	303	6	Primarily driven by lower storm restoration, vegetation management, maintenance and outage expense, and labor due to lower overtime and vacancies, partially offset by higher allocated and indirect costs.
Depreciation & Amortization	148	150	2	
Taxes, Other than Income	24	25	1	
Other income (expense)	(5)	(4)	(1)	
EBIT	335	363	(28)	
Interest Expense	88	89	1	
Income from Ongoing Operations before income taxes	247	274	(28)	
Income Tax Expense	94	105	11	
Net Income (loss) from ongoing operations	**153**	**170**	**(17)**	
Special Item - EEI	(1)	0	(1)	
Discontinued Operations	0	0	0	
Net Income (loss)	$ 153	$ 170	$ (17)	
KY Regulated Financing Costs	(13)	(12)	(0)	
KY Regulated Net Income	140	$ 157	$ (17)	
Earnings Per Share - Ongoing	$ 0.20	$ 0.23	$ (0.02)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E — May 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 446	$ 452	$ (6)	Due primarily to lower sales volumes driven by mild weather in Q1.
Gas Revenues	158	186	(28)	Due primarily to lower sales volumes driven by mild weather in Q1.
Total Revenues	604	638	(34)	
Cost of Sales:				
Fuel Electric Costs	128	125	(3)	
Gas Supply Expenses	65	90	25	Due primarily to lower gas usage as a result of mild weather.
Purchased Power	19	21	2	
Other Electric Cost of Production	5	6	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	11	10	(0)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	16	17	1	
Total Cost of Sales	245	270	26	
Gross Margin:				
Electric Margin	273	279	(6)	See explanations above.
Gas Margin	87	89	(2)	
Total Gross Margin	359	368	(8)	
Operating Expenses:				
O&M	131	136	6	Primarily driven by lower storm restoration, bad debt expense, supplemental contract labor, maintenance and outage expense, and generation labor due to lower overtime and vacancies.
Depreciation & Amortization	60	61	1	
Taxes, Other than Income	12	12	1	
Other income (expense)	(2)	(2)	(0)	
EBIT	155	156	(2)	
Interest Expense	28	29	0	
Income from Ongoing Operations before income taxes	126	128	(1)	
Income Tax Expense	48	49	1	
Net Income (loss) from ongoing operations	**$ 78**	**$ 79**	**$ (1)**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU — May 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 699	$ 750	$ (51)	Due primarily to lower sales volumes driven by mild weather in Q1.
Gas Revenues	0	0	0	
Total Revenues	699	750	(51)	
Cost of Sales:				
Fuel Electric Costs	184	206	21	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	0	0	0	
Purchased Power	26	27	1	
Other Electric Cost of Production	9	11	2	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	17	16	(2)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	13	14	1	
Total Cost of Sales	250	273	23	
Gross Margin:				
Electric Margin	449	478	(28)	See explanations above.
Gas Margin	0	0	0	
Total Gross Margin	449	478	(28)	
Operating Expenses:				
O&M	151	159	7	Primarily driven by lower storm restoration, vegetation management, bad debt expense, supplemental contract labor, maintenance and outage expense, and generation labor due to lower overtime and vacancies.
Depreciation & Amortization	88	89	1	
Taxes, Other than Income	12	12	0	
Other income (expense)	(2)	(2)	0	
EBIT	196	215	(20)	
Interest Expense	40	40	(0)	
Income from Ongoing Operations before income taxes	156	175	(20)	
Income Tax Expense	59	67	8	
Net Income (loss) from ongoing operations	**$ 96**	**$ 109**	**$ (12)**	

Note: Schedules may not sum due to rounding.

O&M								May 2017

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	14	17	3	0	(0)	2	1	(0)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	2	3	0	0	(0)	0	(0)	0
Energy Supply and Analysis	1	1	0	0	-	(0)	(0)	0
Electric Distribution	6	7	1	(0)	1	(0)	0	(0)
Gas Distribution and AMS	3	3	0	(0)	0	0	0	(0)
Safety and Technical Training	0	0	0	0	(0)	0	(0)	0
Customer Services	7	8	1	0	0	0	0	0
Senior VP Operations	**34**	**39**	**5**	**0**	**1**	**2**	**1**	**(0)**
Audit Services	0	0	0	0	-	(0)	0	0
Controller	1	1	0	0	(0)	0	(0)	0
Supply Chain	0	0	0	0	-	(0)	0	(0)
Treasurer	2	2	0	0	-	(0)	0	0
State Regulation and Rates	0	0	0	0	-	0	0	0
Other	0	0	(0)	0	-	(0)	0	(0)
Chief Financial Officer	**4**	**4**	**0**	**0**	**(0)**	**0**	**0**	**0**
General Counsel	**2**	**3**	**1**	**0**	**0**	**0**	**0**	**0**
Human Resources	**1**	**1**	**0**	**0**	**(0)**	**0**	**(0)**	**0**
Information Technology	**4**	**5**	**0**	**0**	**(0)**	**0**	**0**	**(0)**
Corporate	**9**	**8**	**(0)**	**(0)**	**0**	**0**	**(0)**	**(0)**
Enterprise Security	**0**	**0**	**0**	**(0)**	**-**	**0**	**0**	**0**
Utility Total	**53**	**59**	**6**	**1**	**1**	**2**	**2**	**0**
Nonutility Total	**2**	**2**	**(1)**	**(0)**	**0**	**(0)**	**0**	**(0)**
O&M Total MTD	**56**	**61**	**5**	**0**	**1**	**2**	**2**	**(0)**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	84	90	6	2	(0)	1	5	(1)
Project Engineering	0	0	0	0	-	(0)	(0)	0
Transmission	12	13	1	(0)	(0)	1	(0)	0
Energy Supply and Analysis	5	5	0	(0)	-	0	0	0
Electric Distribution	28	31	3	(0)	4	(2)	0	0
Gas Distribution and AMS	15	14	(1)	0	(0)	0	0	(0)
Safety and Technical Training	2	2	(0)	(0)	(0)	(0)	(0)	0
Customer Services	38	40	2	(0)	1	0	0	1
SVP Operations	**184**	**195**	**11**	**1**	**4**	**1**	**5**	**(0)**
Audit Services	1	1	0	0	-	0	0	0
Controller	4	4	(0)	(0)	(0)	0	0	0
Supply Chain	2	2	0	0	(0)	0	0	0
Treasurer	10	10	0	(0)	-	(0)	(0)	0
State Regulation and Rates	1	1	0	(0)	-	0	(0)	0
Other	1	1	0	0	-	0	0	(0)
Chief Financial Officer	**18**	**19**	**0**	**(0)**	**(0)**	**0**	**(0)**	**0**
General Counsel	**11**	**12**	**1**	**0**	**0**	**0**	**(0)**	**1**
Human Resources	**3**	**3**	**0**	**0**	**(0)**	**0**	**(0)**	**0**
Information Technology	**22**	**23**	**1**	**0**	**(0)**	**1**	**(0)**	**0**
Corporate	**43**	**43**	**(0)**	**(1)**	**0**	**0**	**(0)**	**0**
Enterprise Security	**1**	**1**	**0**	**(0)**	**-**	**0**	**0**	**0**
Utility Total	**282**	**295**	**13**	**1**	**4**	**3**	**5**	**1**
Nonutility Total	**15**	**8**	**(7)**	**(4)**	**(0)**	**(1)**	**(0)**	**(2)**
O&M Total YTD	**297**	**303**	**6**	**(3)**	**4**	**2**	**5**	**(1)**

Note: Schedules may not sum due to rounding.

Financing Activities — May 2017

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance
PCB			
Beg Bal	$ 898.8	$ 898.8	$ 0.0
End Bal	898.8	898.8	(0.0)
Ave Bal	**$ 898.8**	**$ 898.8**	**$ (0.0)**
Interest Exp	**$ 5.6**	**$ 5.1**	**$ (0.5)**
Rate	**1.49%**	**1.35%**	**-0.14%**
FMB/Sr Nts/Loan with PPL			
Beg Bal	$ 4,210.0	$ 4,210.0	$ 0.0
End Bal	4,210.0	4,210.0	0.0
Ave Bal	**$ 4,210.0**	**$ 4,210.0**	**$ 0.0**
Interest Exp	**$ 76.3**	**$ 76.8**	**$ 0.5**
Rate	**4.32%**	**4.35%**	**0.03%**
Short-term Debt			
Beg Bal	$ 348.1	$ 509.7	$ 161.6
End Bal	342.1	586.7	244.6
Ave Bal (1)	**$ 345.1**	**$ 548.2**	**$ 203.1**
Interest Exp	**$ 2.0**	**$ 2.5**	**$ 0.5**
Rate	**1.63%**	**1.10%**	**-0.53%**
Unamortized Debt Expense Bonds			
Beg Bal	$ (44.0)	$ (43.2)	$ 0.7
End Bal	(42.8)	(41.6)	1.2
Ave Bal	**$ (43.4)**	**$ (42.4)**	**$ 1.0**
Total End Bal	**$ 5,408.0**	**$ 5,653.8**	**$ 245.8**
Total Average Bal	**$ 5,364.7**	**$ 5,614.6**	**$ 249.8**
Total Expense Excl I/C (2)	**$ 88.2**	**$ 88.9**	**$ 0.7**
Rate	**3.89%**	**3.74%**	**-0.14%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use the average of the beginning and ending balances.
(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(3)	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 114		$ 186
LG&E	500	190		310
KU	598	38	$ 198	362
TOTAL	$ 1,398	$ 342	$ 198	$ 858

(3) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2017 Actual YTD	LKE 2017 Budget YTD	LG&E 2017 Actual YTD	LG&E 2017 Budget YTD	KU 2017 Actual YTD	KU 2017 Budget YTD
CFO pre-WC / Debt	19%	18%	26%	25%	24%	25%
CFO pre-WC + Interest / Interest	5.7	5.7	7.7	7.7	6.8	7.4
CFO pre-WC - Dividends / Debt	13%	14%	18%	20%	14%	15%
Debt to Capitalization[2]	47%	48%	38%	39%	38%	39%

Credit Metrics Moody's	LKE 2017 BP 2018	LKE 2017 BP 2019	LG&E 2017 BP 2018	LG&E 2017 BP 2019	KU 2017 BP 2018	KU 2017 BP 2019
CFO pre-WC / Debt	18%	18%	27%	29%	26%	26%
CFO pre-WC + Interest / Interest	6.0	5.7	8.5	8.7	7.8	7.6
CFO pre-WC - Dividends / Debt	11%	15%	25%	22%	20%	18%
Debt to Capitalization[2]	50%	49%	38%	36%	37%	37%

[1] Actuals represent a trailing 12 months.
[2] For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2016	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — May 2017

($ Millions)

	5/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 10	$ 106	$ (96)	Primarily due to LKE other excess cash from dividends in budget not used to pay down CEP Reserves.
Accounts Receivable (Trade)	379	390	(12)	
Inventory	256	242	14	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	27	19	8	
Prepayments and other current assets	55	39	16	Primarily due to increases in prepayments, preliminary survey costs, other transportation and engineering amounts, and timing of accounts receivable.
Total Current Assets	726	796	(69)	
Property, Plant, and Equipment	11,679	11,801	(122)	
Intangible Assets	91	93	(2)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	837	915	(78)	
Goodwill	997	997	0	
Other Long-term Assets	78	81	(3)	
Total Assets	**$ 14,409**	**$ 14,684**	**$ (274)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 234	$ 211	$ 23	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	116	0	116	Dividends are considered declared and paid in the same month in the budget.
Customer Deposits	56	55	2	
Derivative Liability	5	6	(1)	
Accrued Taxes	58	40	18	Budget assumed higher Q1 tax settlement to occur in April 2017.
Regulatory Liabilities Current	15	22	(7)	
Other Current Liabilities	172	174	(2)	
Total Current Liabilities	656	507	149	
Debt - Affiliated Company	514	626	(112)	Used tax settlements and dividends from utilities to pay down CEP reserves.
Debt [(1)]	4,894	5,027	(134)	
Total Debt	5,408	5,654	(246)	
Deferred Tax Liabilities	1,786	1,781	5	
Investment Tax Credit	131	130	1	
Accum Provision for Pension & Related Benefits	338	410	(73)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	374	362	12	
Regulatory Liabilities Non Current	898	861	37	
Derivative Liability	26	30	(4)	
Other Liabilities	189	198	(9)	
Total Deferred Credits and Other Liabilities	3,742	3,773	(31)	
Equity	4,604	4,750	(146)	
Total Liabilities and Equity	**$ 14,409**	**$ 14,684**	**$ (274)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E
May 2017

($ Millions)

	5/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 4	$ 5	$ (1)	
Accounts Receivable (Trade)	157	169	(11)	
Inventory	107	101	7	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	14	5	9	
Prepayments and other current assets	45	47	(2)	
Total Current Assets	327	327	0	
Property, Plant, and Equipment	5,044	5,115	(71)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	451	498	(47)	
Goodwill	0	0	0	
Other Long-term Assets	17	21	(4)	
Total Assets	**$ 5,845**	**$ 5,967**	**$ (122)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 139	$ 146	$ (8)	
Dividends Payable to Affiliated Companies	35	37	(2)	
Customer Deposits	27	26	1	
Derivative Liability	5	6	(1)	
Accrued Taxes	32	25	7	
Regulatory Liabilities Current	4	4	(0)	
Other Current Liabilities	67	81	(13)	Primarily due to timing of cash payments & ARO reclassification from current to long term partially offset by an increase in customer advances.
Total Current Liabilities	308	325	(17)	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	1,808	1,875	(67)	
Total Debt	1,808	1,875	(67)	
Deferred Tax Liabilities	1,006	1,004	2	
Investment Tax Credit	36	36	(0)	
Accum Provision for Pension & Related Benefits	52	74	(23)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	113	99	14	Primarily due to the reclassification of ARO from current to long term.
Regulatory Liabilities Non Current	368	350	18	
Derivative Liability	26	30	(4)	
Other Liabilities	87	92	(5)	
Total Deferred Credits and Other Liabilities	1,687	1,686	1	
Equity	2,042	2,081	(39)	
Total Liabilities and Equity	**$ 5,845**	**$ 5,967**	**$ (122)**	

(1) Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

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Balance Sheet - KU

May 2017

($ Millions)

	5/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 6	$ 5	$ 1	
Accounts Receivable (Trade)	221	221	(0)	
Inventory	149	141	7	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	13	14	(1)	
Prepayments and other current assets	28	21	6	
Total Current Assets	416	402	14	
Property, Plant, and Equipment	6,627	6,678	(51)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	383	416	(33)	
Goodwill	0	0	0	
Other Long-term Assets	59	57	2	
Total Assets	**$ 7,498**	**$ 7,566**	**$ (69)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 132	$ 110	$ 22	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	40	52	(12)	Due to lower Net Income in the previous quarter.
Customer Deposits	30	28	1	
Derivative Liability	0	0	0	
Accrued Taxes	36	27	9	
Regulatory Liabilities Current	11	17	(6)	
Other Current Liabilities	67	56	11	Primarily due to ARO reclassification from long term to current.
Total Current Liabilities	316	290	26	
Debt - Affiliated Company	0	0	0	
Debt [1]	2,363	2,430	(66)	
Total Debt	2,363	2,430	(66)	
Deferred Tax Liabilities	1,208	1,244	(37)	
Investment Tax Credit	95	94	1	
Accum Provision for Pension & Related Benefits	46	66	(21)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	261	262	(2)	
Regulatory Liabilities Non Current	458	437	21	
Derivative Liability	0	0	0	
Other Liabilities	49	52	(3)	
Total Deferred Credits and Other Liabilities	2,116	2,157	(41)	
Equity	2,703	2,690	13	
Total Liabilities and Equity	**$ 7,498**	**$ 7,566**	**$ (69)**	

[1] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

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Performance Report

June 2017

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Kentucky Regulated Dashboard

June 2017

	Current Month		YTD		Full Year	
Safety	Actual	PY	Actual	PY	Forecast	PY
TCIR - Employees[1]	0.34	1.56	1.00	0.97	1.35	1.12
Employee lost-time incidents	2	1	4	2	9	5
Reliability	Actual	Budget	Actual	Budget	Forecast	Budget
Generation Volumes	2,860	3,076	15,877	16,909	33,393	34,425
Utility EFOR	6.1%	5.0%	4.4%	5.0%	N/A	5.0%
Utility EAF	91.1%	92.5%	82.8%	85.5%	N/A	85.2%
Steam Fleet Commercial Availability	95.7%	93.0%	93.8%	93.0%	N/A	93.0%
Combined SAIFI	0.09	0.13	0.40	0.55	N/A	1.03
Combined SAIDI (minutes)	9.38	12.24	37.49	48.24	N/A	93.20
GwH Sales	Actual	Budget	Actual	Budget	Forecast	Budget
Residential	887	906	4,768	5,253	10,121	10,668
Commercial	697	727	3,762	3,840	7,772	7,882
Industrial	770	886	4,552	4,777	9,256	9,706
Municipals	155	161	856	923	1,756	1,846
Other	232	250	1,313	1,352	2,741	2,753
Off-System Sales	6	18	221	136	329	244
Total	2,746	2,948	15,472	16,280	31,974	33,098
Weather-Normalized Sales Growth			TTM			
Residential			0.63%			
Commercial			1.72%			
Industrial			-2.39%			
Municipal			-1.75%			
Other			-0.60%			
Total			-0.24%			

	Current Month		YTD		Full Year	
Margins ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Electric Margins[2]	$155	$162	$877	$918	$1,865	$1,948
Gas Margins	$10	$10	$97	$99	$178	$183
Capital Expenditures ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Total[2]	$61	$95	$345	$469	$1,066	$1,107
O&M ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
O&M – Management View[2] [3]	$50	$61	$346	$364	$719	$749
O&M – GAAP View[2] [4]	$60	$72	$399	$418	$832	$864
Head Count	Actual	Budget	Actual	Budget	Forecast	Budget
Full-time Employees	3,485	3,607	3,485	3,607	3,565	3,591
Other Metrics	Actual	PY	Actual	PY	Forecast	PY
Environmental Events	0	0	3	0	N/A	3
NERC Possible Violations[5]	0	0	4	1	N/A	5

	TTM	Full Year	
Financial Metrics	Actual	Forecast	Budget
Utility ROE[6]	9.8%	9.6%	9.8%
Average Utility Capitalization ($ millions)	$8,897	$9,021	$9,174

Variance Explanations

Lower margins MTD primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $5 million and lower retail rate mechanism revenue of $2 million.

Lower margins YTD primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $39 million, lower retail rate mechanism revenue of $5 million and lower gas margins of $2 million partially offset by $2 million of other margin components.

Lower O&M MTD primarily due to lower labor and burdens of $4 million, lower maintenance and materials of $3 million, lower storm and vegetation management expenses of $2 million and other smaller variances combined $3 million.

Lower O&M YTD primarily due to lower maintenance and outage expenses of $5 million, lower storm and vegetation management expenses of $4 million, lower labor and burdens of $3 million and lower uncollectible expense of $1 million and other smaller variances combined $5 million.

Major Developments

The Company continues to build on its outstanding customer satisfaction performance as it recently won another J.D. Power award. KU ranked first (with a score of 761) and LG&E second (with a score of 743) among the mid-sized utilities in the Midwest region of the 2017 Electric Utility Residential Customer Satisfaction study. LKE also won four awards last year and has earned a total of 20 awards for overall customer satisfaction. These results reflect employee's continued focus on the customer experience.

The KPSC issued orders in the rate case proceeding on June 22nd approving, with certain modifications, the proposed stipulations filed in April and May. On June 29th, the KPSC issued additional orders correcting certain revenue requirement and rate calculations and making other technical corrections. These orders modified the stipulations and reflect a $57 million electric base rate increase for LG&E, a $52 million electric base rate increase for KU, and a $7 million gas base rate increase for LG&E, based on an authorized return on equity of 9.7 percent. Consistent with the stipulations, the orders also approved LKE's request for implementing a Distribution Automation program and its withdrawal of a request for a Certificate of Public Convenience and Necessity for the Advanced Metering System program. The new rates and all elements of the orders became effective July 1, 2017. The KPSC also adjusted the return on equity for our ECR mechanism to be consistent with the rate case order.

Governor Matt Bevin has appointed Talina Rose Mathews, the current executive director of the KPSC, to serve as a Commissioner. Talina replaces former Commissioner Daniel Logsdon, who resigned in June, just prior to the end of his term, to pursue other interests. She assumed the position immediately and will serve a four-year term. An economist by background, Talina brings a wealth of experience in the utility sector and state government. The appointment is subject to confirmation by the Senate.

LG&E long-term gas main replacement project is nearing completion as LG&E completed the installation of plastic pipe in the final section of its system. This initiative began in 1996 when the Company established a program to replace 540 miles of aging cast iron, wrought iron and bare steel natural gas pipelines, for replacement, primarily with more durable plastic natural gas pipelines. This upgrade program enabled LKE to enhance the safety of our system for customers well in advance of its peers, and allowed for additional infrastructure upgrades.

A very significant milestone was achieved recently as the Trimble County Landfill Project received its permit from the Corps of Engineers, representing the final regulatory approval needed to begin construction of the landfill. The approval marked the completion of a nine year process which overcame many external challenges. LKE is currently evaluating construction bids and expects to award the contract in the next few months.

LKE earned 15 communications awards in various categories during the recent Utility Communicators International conference. The 2017 Better Communications Competition receives entries from utilities of all sizes across the U.S. and Canada. The conference is expected to be held in Louisville next year.

As expected, the Kentucky Waterways Alliance and the Sierra Club recently filed a citizen suit complaint against KU alleging discharges at the E.W. Brown plant in violation of the Clean Water Act and Resource Conservation and Recovery Act. This action follows prior notices of intent to file a citizen suit submitted in October and November 2015 and October 2016. We will continue to defend the lawsuit and attempt to work toward a satisfactory solution.

Significant Future Events

There are no significant future events to report at this time.

(1) Full year forecast amount shown represents target.

(2) Includes net impact of proposed settlement stipulation adjustments of deferred AMS Capital and O&M expense, lower depreciation expense and the offsetting revenue reduction included in margins.

(3) Net of cost recovery mechanisms and variable costs of production.

(4) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses

(5) The possible violation issues for YTD Actual is believed to be minimal risk.

(6) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — June 2017

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 240	$ 255	$ (15)	Due primarily to lower than budgeted sales volumes.
Gas Revenues	14	14	(0)	
Total Revenues	254	269	(15)	
Cost of Sales:				
Fuel Electric Costs	66	73	6	Primarily due to decreased generation as a result of milder weather than Budget.
Gas Supply Expenses	3	3	0	
Purchased Power	4	5	1	
Other Electric Cost of Production	3	4	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	7	7	(0)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	6	0	
Total Cost of Sales	89	98	8	
Gross Margin:				
Electric Margin	155	162	(7)	See explanations above.
Gas Margin	10	10	0	
Total Gross Margin	164	171	(7)	
Operating Expenses:				
O&M	50	61	12	Primarily due to lower labor and burdens, lower maintenance and materials, lower storm and vegetation management expenses and other smaller variances.
Depreciation & Amortization	30	30	0	
Taxes, Other than Income	5	5	(0)	
Equity in Earnings	0	0	0	
Other income (expense)	(1)	(0)	(0)	
EBIT	79	74	4	
Interest Expense	19	18	(1)	
Income from Ongoing Operations before income taxes	59	57	3	
Income Tax Expense	22	21	(1)	
Net Income (loss) from ongoing operations	**37**	**35**	**2**	
Special Item - EEI	0	0	0	
Discontinued Operations	0	0	0	
Net Income (loss)	$ 37	$ 35	$ 2	
KY Regulated Financing Costs	(3)	$ (2)	(0)	
KY Regulated Net Income	$ 35	$ 33	$ 2	
Earnings Per Share - Ongoing	$ 0.05	$ 0.05	$ 0.00	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — June 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,361	$ 1,431	$ (70)	Due primarily to lower sales volumes driven by mild weather in Q1.
Gas Revenues	172	200	(28)	Due primarily to lower sales volumes driven by mild weather in Q1.
Total Revenues	1,533	1,631	(98)	
Cost of Sales:				
Fuel Electric Costs	375	401	26	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	69	94	25	Due primarily to lower gas usage as a result of mild weather.
Purchased Power	29	30	1	
Other Electric Cost of Production	18	20	3	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	35	33	(2)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	35	37	2	
Total Cost of Sales	560	614	54	
Gross Margin:				
Electric Margin	877	918	(41)	See explanations above.
Gas Margin	97	99	(2)	
Total Gross Margin	973	1017	(44)	
Operating Expenses:				
O&M	346	364	18	Primarily due to lower maintenance and outage expenses, lower storm and vegetation management expenses, lower labor and burdens and lower uncollectible expense and other smaller variances.
Depreciation & Amortization	178	180	2	
Taxes, Other than Income	29	30	1	
Other income (expense)	(6)	(4)	(1)	
EBIT	414	438	(24)	
Interest Expense	108	107	(1)	
Income from Ongoing Operations before income taxes	306	331	(25)	
Income Tax Expense	116	126	10	
Net Income (loss) from ongoing operations	**190**	**205**	**(15)**	
Special Item - EEI	(1)	0	(1)	
Discontinued Operations	0	0	0	
Net Income (loss)	$ 190	$ 205	$ (15)	
KY Regulated Financing Costs	(15)	(15)	(0)	
KY Regulated Net Income	175	$ 190	$ (15)	
Earnings Per Share - Ongoing	$ 0.26	$ 0.27	$ (0.02)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E

June 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 545	$ 558	$ (14)	Due primarily to lower sales volumes driven by mild weather in Q1.
Gas Revenues	172	200	(28)	Due primarily to lower sales volumes driven by mild weather in Q1.
Total Revenues	717	758	(42)	
Cost of Sales:				
Fuel Electric Costs	153	152	(1)	
Gas Supply Expenses	69	94	25	Due primarily to lower gas usage as a result of mild weather.
Purchased Power	23	27	4	
Other Electric Cost of Production	6	8	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	13	13	0	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	19	20	1	
Total Cost of Sales	284	314	30	
Gross Margin:				
Electric Margin	336	346	(9)	See explanations above.
Gas Margin	97	99	(2)	
Total Gross Margin	433	444	(12)	
Operating Expenses:				
O&M	152	164	12	Primarily driven by lower storm restoration, supplemental contract labor, maintenance expense, and labor due to lower overtime and vacancies.
Depreciation & Amortization	72	73	1	
Taxes, Other than Income	14	15	1	
Other income (expense)	(3)	(2)	(0)	
EBIT	192	191	1	
Interest Expense	35	35	0	
Income from Ongoing Operations before income taxes	157	156	1	
Income Tax Expense	60	60	(1)	
Net Income (loss) from ongoing operations	**$ 97**	**$ 96**	**$ 1**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU — June 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 842	$ 903	$ (60)	Due primarily to lower sales volumes driven by mild weather in Q1.
Gas Revenues	0	0	0	
Total Revenues	842	903	(60)	
Cost of Sales:				
Fuel Electric Costs	225	251	26	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	0	0	0	
Purchased Power	28	30	1	
Other Electric Cost of Production	11	13	2	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	22	20	(2)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	16	16	1	
Total Cost of Sales	302	330	28	
Gross Margin:				
Electric Margin	540	572	(32)	See explanations above.
Gas Margin	0	0	0	
Total Gross Margin	540	572	(32)	
Operating Expenses:				
O&M	177	191	14	Primarily driven by lower storm restoration, vegetation management, supplemental contract labor, maintenance and outage expense, and labor due to lower overtime and vacancies.
Depreciation & Amortization	106	107	1	
Taxes, Other than Income	15	15	0	
Other income (expense)	(2)	(2)	0	
EBIT	240	257	(17)	
Interest Expense	48	48	(0)	
Income from Ongoing Operations before income taxes	192	209	(17)	
Income Tax Expense	73	79	6	
Net Income (loss) from ongoing operations	**$ 119**	**$ 130**	**$ (11)**	

Note: Schedules may not sum due to rounding.

Income Statement: Forecast vs. Budget - LKE Consolidated — June 2017

($ Millions)

	Full Year			
	Q2 Forecast	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,883	$ 3,017	$ (134)	Due primarily to lower sales volumes driven by mild weather in Q1, a reduction in the electric load forecast for the remainder of 2017, and lower than budgeted KPSC rates effective July 1, 2017.
Gas Revenues	298	329	(31)	Due primarily to lower sales volumes driven by mild weather in Q1 and lower than budgeted KPSC rates effective July 1, 2017.
Total Revenues	3,181	3,346	(165)	
Cost of Sales:				
Fuel Electric Costs	787	813	26	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	110	135	26	Due primarily to lower gas usage as a result of mild weather.
Purchased Power	59	60	1	
Other Electric Cost of Production	38	41	3	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	75	74	(1)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	71	93	22	Primarily due to lower depreciation rates.
Total Cost of Sales	1,139	1,216	77	
Gross Margin:				
Electric Margin	1,865	1,948	(83)	See explanations above.
Gas Margin	178	183	(4)	See explanations above.
Total Gross Margin	2,043	2,130	(87)	
Operating Expenses:				
O&M	719	749	30	Lower O&M primarily due to cost savings across all business units for the year partially offset by increased indirect charges from PPL.
Depreciation & Amortization	378	395	18	Primarily due to lower depreciation rates.
Taxes, Other than Income	60	61	1	
Total Operating Expenses	1,157	1,205	48	
Other income (expense)	(9)	(8)	(1)	
EBIT	877	917	(40)	
Interest Expense	217	217	0	
Income from Ongoing Operations before income taxes	660	700	(40)	
Income Tax Expense	251	267	16	
Net Income (loss) from ongoing operations	**409**	**433**	**$ (24)**	
Special Item - EEI	(1)	0	(1)	
Discontinued Operations	1	(0)	1	
Net Income (loss)	$ 410	$ 433	$ (24)	
KY Regulated Financing Costs	(30)	(30)	(0)	
KY Regulated Net Income	$ 379	$ 403	$ (24)	
Earnings Per Share - Ongoing	$ 0.55	$ 0.58	$ (0.03)	

Note: Schedules may not sum due to rounding.

O&M										June 2017

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	5	6	2	(0)	0	1	1	(0)
Project Engineering	0	0	0	0	-	-	0	(0)
Transmission	2	3	1	0	(0)	0	(0)	0
Energy Supply and Analysis	1	1	0	0	-	(0)	0	0
Electric Distribution	5	6	1	(0)	1	(0)	0	0
Gas Distribution	2	2	(0)	(0)	0	(0)	-	-
Advanced Metering System	0	-	(0)	-	-	-	-	(0)
Safety and Technical Training	0	0	0	0	(0)	0	0	0
Customer Services	3	3	0	(0)	0	(0)	0	(0)
SVP Operations Total	**19**	**23**	**4**	**(0)**	**2**	**1**	**1**	**0**
Audit Services	0	0	0	0	-	-	0	0
Controller	1	1	0	0	-	0	0	0
Supply Chain	0	0	0	0	-	(0)	0	(0)
Treasurer	1	1	0	0	-	-	0	0
State Regulation and Rates	0	0	0	0	-	0	(0)	0
Other	0	0	0	0	-	0	0	0
Chief Financial Officer Total	**2**	**2**	**0**	**0**	**-**	**0**	**(0)**	**0**
General Counsel	**1**	**1**	**0**	**(0)**	**0**	**0**	**0**	**0**
Human Resources	**0**	**0**	**0**	**0**	**(0)**	**0**	**0**	**0**
Information Technology	**1**	**1**	**0**	**(0)**	**(0)**	**0**	**(0)**	**0**
Corporate	**1**	**4**	**3**	**3**	**0**	**(0)**	**-**	**0**
Enterprise Security	**0**	**0**	**0**	**(0)**	**-**	**0**	**0**	**0**
Utility Total	**24**	**32**	**8**	**3**	**2**	**2**	**1**	**1**
Nonutility Total	**25**	**29**	**4**	**3**	**0**	**0**	**1**	**(0)**
O&M Total MTD	**50**	**61**	**12**	**5**	**2**	**2**	**2**	**0**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	47	47	0	(0)	(0)	2	(1)	(1)
Project Engineering	0	0	0	0	-	(0)	(0)	(0)
Transmission	14	16	2	(0)	(0)	2	(0)	0
Energy Supply and Analysis	6	6	0	(0)	-	(0)	0	0
Electric Distribution	31	35	4	(0)	5	(2)	1	0
Gas Distribution	13	13	(0)	0	(0)	0	-	-
Advanced Metering System	0	-	(0)	(0)	-	-	-	(0)
Safety and Technical Training	3	3	(0)	(0)	(0)	0	(0)	0
Customer Services	17	17	1	(0)	1	0	0	(0)
SVP Operations Total	**132**	**138**	**7**	**(0)**	**5**	**2**	**(0)**	**(1)**
Audit Services	1	1	0	0	-	0	0	0
Controller	4	4	0	(0)	(0)	0	0	0
Supply Chain	1	1	0	0	(0)	(0)	0	0
Treasurer	5	5	0	(0)	-	(0)	0	0
State Regulation and Rates	1	1	0	(0)	-	0	(0)	0
Other	1	1	0	0	-	0	0	(0)
Chief Financial Officer Total	**14**	**14**	**0**	**(0)**	**(0)**	**0**	**(0)**	**0**
General Counsel	**5**	**6**	**0**	**(0)**	**0**	**(0)**	**0**	**1**
Human Resources	**0**	**0**	**0**	**0**	**(0)**	**0**	**(0)**	**0**
Information Technology	**8**	**8**	**1**	**(0)**	**(0)**	**1**	**(0)**	**0**
Corporate	**20**	**23**	**3**	**3**	**0**	**0**	**0**	**0**
Enterprise Security	**1**	**1**	**0**	**(0)**	**-**	**0**	**0**	**0**
Utility Total	**180**	**191**	**11**	**2**	**5**	**3**	**(0)**	**1**
Nonutility Total	**166**	**173**	**7**	**1**	**0**	**0**	**7**	**(2)**
O&M Total YTD	**346**	**364**	**18**	**3**	**6**	**4**	**7**	**(1)**

	Full Year							
	Forecast	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	207	217	9	3	(1)	1	7	(1)
Project Engineering	1	1	0	0	-	(0)	(0)	0
Transmission	33	34	2	0	0	1	(0)	0
Energy Supply and Analysis	13	13	0	0	-	0	0	0
Electric Distribution	70	74	5	0	6	(2)	1	0
Gas Distribution	36	35	(1)	(0)	(1)	0	(0)	(0)
Advanced Metering System	0	3	3	1	-	2	-	(0)
Safety and Technical Training	5	5	(0)	(0)	(0)	(0)	0	0
Customer Services	97	99	2	(0)	1	1	(0)	1
SVP Operations Total	**462**	**482**	**20**	**4**	**6**	**3**	**7**	**(0)**
Audit Services	2	2	0	0	-	0	0	0
Controller	9	9	0	0	(0)	0	0	0
Supply Chain	4	4	0	0	(0)	(0)	0	0
Treasurer	23	24	1	0	-	(0)	0	1
State Regulation and Rates	4	4	0	(0)	-	0	0	(0)
Other	2	2	0	0	-	0	0	(0)
Chief Financial Officer Total	**44**	**46**	**2**	**0**	**(0)**	**0**	**0**	**1**
General Counsel	**30**	**31**	**2**	**0**	**0**	**1**	**0**	**1**
Human Resources	**7**	**7**	**1**	**0**	**(0)**	**0**	**(0)**	**0**
Information Technology	**55**	**56**	**2**	**2**	**(0)**	**1**	**(0)**	**(1)**
Corporate	**91**	**105**	**14**	**13**	**0**	**0**	**(0)**	**2**
Enterprise Security	**3**	**3**	**0**	**(0)**	**-**	**0**	**0**	[illegible]
Utility Total	**690**	**731**	**40**	**20**	**6**	**5**	**7**	**2**
Nonutility Total	**28**	**18**	**(10)**	**(5)**	**0**	**(1)**	**(0)**	**(4)**
O&M Total YTD	**719**	**749**	**30**	**15**	**6**	**4**	**7**	**(2)**

Note: Schedules may not sum due to rounding.

Financing Activities — June 2017

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB						
Beg Bal	$ 898.8	$ 898.8	$ 0.0	$ 898.8	$ 898.8	$ 0.0
End Bal	900.1	898.7	(1.4)	900.0	898.7	(1.4)
Ave Bal	**$ 899.4**	**$ 898.8**	**$ (0.7)**	**$ 899.4**	**$ 898.7**	**$ (0.7)**
Interest Exp	**$ 8.0**	**$ 6.1**	**$ (2.0)**	**$ 15.0**	**$ 11.9**	**$ (3.1)**
Rate	**1.78%**	**1.34%**	**-0.43%**	**1.65%**	**1.31%**	**-0.34%**
FMB/Sr Nts/Loan with PPL						
Beg Bal	$ 4,210.0	$ 4,210.0	$ 0.0	$ 4,210.0	$ 4,210.0	$ 0.0
End Bal	4,210.0	4,245.0	35.0	4,601.8	4,608.5	6.7
Ave Bal	**$ 4,210.0**	**$ 4,227.5**	**$ 17.50**	**$ 4,405.9**	**$ 4,409.2**	**$ 3.33**
Interest Exp	**$ 91.9**	**$ 92.2**	**$ 0.3**	**$ 184.0**	**$ 187.7**	**$ 3.7**
Rate	**4.34%**	**4.34%**	**0.00%**	**4.12%**	**4.20%**	**0.08%**
Short-term Debt						
Beg Bal	$ 348.1	$ 509.7	$ 161.6	$ 348.1	$ 509.7	$ 161.6
End Bal	417.9	606.9	189.0	423.7	530.2	106.5
Ave Bal (1)	**$ 383.0**	**$ 558.3**	**$ 175.3**	**$ 385.9**	**$ 520.0**	**$ 134.1**
Interest Exp	**$ 2.5**	**$ 3.2**	**$ 0.6**	**$ 7.6**	**$ 6.9**	**$ (0.7)**
Rate	**1.66%**	**1.13%**	**-0.53%**	**1.95%**	**1.31%**	**-0.64%**
Unamortized Debt Expense Bonds						
Beg Bal	$ (44.0)	$ (43.2)	$ 0.7	$ (44.0)	$ (43.2)	$ 0.75
End Bal	(43.3)	(41.9)	1.4	(41.4)	(42.0)	(0.6)
Ave Bal	**$ (43.6)**	**$ (42.5)**	**$ 1.1**	**$ (42.7)**	**$ (42.6)**	**$ 0.1**
Total End Bal	**$ 5,484.7**	**$ 5,708.7**	**$ 224.0**	**$ 5,884.1**	**$ 5,995.3**	**$ 111.2**
Total Average Bal	**$ 5,369.3**	**$ 5,642.0**	**$ 272.7**	**$ 5,648.5**	**$ 5,785.3**	**$ 136.8**
Total Expense Excl I/C (2)	**$ 107.5**	**$ 106.8**	**$ (0.7)**	**$ 216.7**	**$ 217.2**	**$ 0.5**
Rate	**3.95%**	**3.74%**	**-0.21%**	**3.76%**	**3.68%**	**-0.08%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use the average of the beginning and ending balances.
(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(3)	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 159		$ 141
LG&E	500	207		293
KU	598	51	$ 198	349
TOTAL	$ 1,398	$ 418	$ 198	$ 782

(3) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2017 Actual YTD	LKE 2017 Budget YTD	LG&E 2017 Actual YTD	LG&E 2017 Budget YTD	KU 2017 Actual YTD	KU 2017 Budget YTD
CFO pre-WC / Debt	19%	18%	27%	26%	25%	27%
CFO pre-WC + Interest / Interest	5.8	5.8	8.1	8.1	7.2	7.8
CFO pre-WC - Dividends / Debt	12%	12%	19%	22%	15%	18%
Debt to Capitalization[2]	47%	48%	38%	39%	38%	38%

Credit Metrics Moody's	LKE 2017 BP 2018	LKE 2017 BP 2019	LG&E 2017 BP 2018	LG&E 2017 BP 2019	KU 2017 BP 2018	KU 2017 BP 2019
CFO pre-WC / Debt	18%	18%	27%	29%	26%	26%
CFO pre-WC + Interest / Interest	6.0	5.7	8.5	8.7	7.8	7.6
CFO pre-WC - Dividends / Debt	11%	15%	25%	22%	20%	18%
Debt to Capitalization[2]	50%	49%	38%	36%	37%	37%

[1] Actuals represent a trailing 12 months.
[2] For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2016	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.
Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — June 2017

($ Millions)

	6/30/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 19	$ 14	$ 5	
Accounts Receivable (Trade)	373	413	(41)	Primarily due to lower than budgeted revenues and variance between actual and budgeted Acccounts Receivable lag factors.
Inventory	257	239	18	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	23	18	5	
Prepayments and other current assets	75	39	36	Primarily due to accounts receivable related to refined coal.
Total Current Assets	747	723	23	
Property, Plant, and Equipment	11,634	11,850	(217)	
Intangible Assets	90	92	(2)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	830	917	(87)	Primarily due to MTM adjustment of Swaps, a pension funded status adjustment due to change in discount rate decrease in ARO balance.
Goodwill	997	997	0	
Other Long-term Assets	78	81	(2)	
Total Assets	**$ 14,377**	**$ 14,662**	**$ (285)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 231	$ 215	$ 16	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	57	55	2	
Derivative Liability	5	6	(1)	
Accrued Taxes	42	17	25	Budget assumed higher Q2 tax settlement to occur in April 2017.
Regulatory Liabilities Current	14	21	(7)	
Other Current Liabilities	219	189	31	Primarily due to reclassfication of ARO amounts between current and long-term and timing of payables and credit cash adjustment.
Total Current Liabilities	567	502	65	
Debt - Affiliated Company	559	681	(121)	Used tax settlements and dividends from utilities to pay down CEP reserves.
Debt [(1)]	4,925	5,028	(103)	
Total Debt	5,485	5,709	(224)	
Deferred Tax Liabilities	1,823	1,828	(4)	
Investment Tax Credit	131	130	1	
Accum Provision for Pension & Related Benefits	344	410	(67)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	292	362	(70)	Primarily due to ARO revaluation and reclassification from long term to current.
Regulatory Liabilities Non Current	902	856	46	
Derivative Liability	25	30	(5)	
Other Liabilities	176	187	(11)	
Total Deferred Credits and Other Liabilities	3,693	3,804	(110)	
Equity	4,631	4,648	(16)	
Total Liabilities and Equity	**$ 14,377**	**$ 14,662**	**$ (285)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E   June 2017

($ Millions)

	6/30/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 7	$ 5	$ 2	
Accounts Receivable (Trade)	164	179	(14)	
Inventory	111	103	8	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	11	4	7	
Prepayments and other current assets	43	46	(4)	
Total Current Assets	336	337	(1)	
Property, Plant, and Equipment	5,048	5,143	(94)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	448	497	(49)	Primarily due to MTM adjustment of Swaps, a pension funded status adjustment due to change in discount rate decrease in ARO balance.
Goodwill	0	0	0	
Other Long-term Assets	16	21	(5)	
Total Assets	**$ 5,855**	**$ 6,004**	**$ (149)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 139	$ 151	$ (12)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	27	26	1	
Derivative Liability	5	6	(1)	
Accrued Taxes	17	15	3	
Regulatory Liabilities Current	4	4	1	
Other Current Liabilities	79	84	(5)	
Total Current Liabilities	271	285	(14)	
Debt - Affiliated Company	0	0	0	
Debt [1]	1,825	1,876	(51)	
Total Debt	1,825	1,876	(51)	
Deferred Tax Liabilities	1,033	1,035	(2)	
Investment Tax Credit	36	36	(0)	
Accum Provision for Pension & Related Benefits	48	73	(25)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	103	99	4	
Regulatory Liabilities Non Current	368	347	21	
Derivative Liability	25	30	(5)	
Other Liabilities	83	90	(7)	
Total Deferred Credits and Other Liabilities	1,697	1,710	(13)	
Equity	2,061	2,133	(71)	
Total Liabilities and Equity	**$ 5,855**	**$ 6,004**	**$ (149)**	

[1] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

Balance Sheet - KU June 2017

($ Millions)

	6/30/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 12	$ 5	$ 7	
Accounts Receivable (Trade)	208	234	(26)	Primarily due to lower than budgeted revenues and variance between actual and budgeted Acccounts Receivable lag factors.
Inventory	147	136	11	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	11	14	(2)	
Prepayments and other current assets	47	22	25	Primarily due to accounts receivable related to refined coal.
Total Current Assets	425	411	14	
Property, Plant, and Equipment	6,577	6,699	(122)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	379	420	(41)	Primarily due to a pension funded status adjustment due to change in discount rate and decrease in ARO balance.
Goodwill	0	0	0	
Other Long-term Assets	60	57	2	
Total Assets	**$ 7,455**	**$ 7,601**	**$ (147)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 137	$ 110	$ 27	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	30	28	1	
Derivative Liability	0	0	0	
Accrued Taxes	16	9	7	
Regulatory Liabilities Current	10	17	(7)	
Other Current Liabilities	93	63	30	Primarily due to ARO reclassification from long term to current.
Total Current Liabilities	285	227	58	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,376	2,429	(52)	
Total Debt	2,376	2,429	(52)	
Deferred Tax Liabilities	1,242	1,283	(41)	
Investment Tax Credit	95	94	1	
Accum Provision for Pension & Related Benefits	38	66	(29)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	189	263	(74)	Primarily due to ARO revaluation and reclassification from long term to current.
Regulatory Liabilities Non Current	462	436	26	
Derivative Liability	0	0	0	
Other Liabilities	42	48	(6)	
Total Deferred Credits and Other Liabilities	2,068	2,191	(123)	
Equity	2,726	2,755	(30)	
Total Liabilities and Equity	**$ 7,455**	**$ 7,601**	**$ (147)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

KU and LG&E Combined
Reconciliation of Allowed Return to
12 months ended June 2017 Regulatory Return
and ROE from Ongoing Operations

Allowed Return (1)		10.0%	
Adjustments (net tax):			
Change in capitalization - non mechanism	-0.1%		Growth in capitalization (rate base) between rate cases does not earn a return
Change in ROE from average mechanism rate base growth	0.0%		Mechanisms have a real-time return
Change in weighted cost of debt	-0.1%		Higher interest rates and borrowing
Change in margins	-0.8%		Lower revenue
Change in allowed expenses	0.7%		Lower expense
		-0.3%	
Actual Regulated ROE		9.8%	

(1) Based on the base rate filings with test years ending 6/30/16 KPSC, 12/31/14 VA and the FERC Formula Rate Filing for the period ended 12/31/15.

Performance Report

July 2017

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Kentucky Regulated Dashboard — July 2017

	Current Month		YTD		Full Year	
Safety	Actual	PY	Actual	PY	Forecast	PY
TCIR - Employees[1]	2.01	0.34	1.13	0.87	1.35	1.12
Employee lost-time incidents	2	0	6	2	10	5
Reliability	Actual	Budget	Actual	Budget	Forecast	Budget
Generation Volumes	3,217	3,290	19,094	20,199	33,320	34,425
Utility EFOR	2.6%	5.0%	4.1%	5.0%	N/A	5.0%
Utility EAF	96.1%	92.5%	84.7%	86.5%	N/A	85.2%
Steam Fleet Commercial Availability	97.9%	93.0%	94.4%	93.0%	N/A	93.0%
Combined SAIFI	0.13	0.12	0.53	0.67	N/A	1.03
Combined SAIDI (minutes)	12.19	13.75	49.70	61.99	N/A	93.20
GwH Sales	Actual	Budget	Actual	Budget	Forecast	Budget
Residential	1,138	1,083	5,906	6,337	10,188	10,668
Commercial	773	751	4,536	4,590	7,798	7,882
Industrial	778	859	5,329	5,636	9,218	9,706
Municipals	173	174	1,030	1,097	1,760	1,846
Other	246	251	1,559	1,603	2,735	2,753
Off-System Sales	7	20	227	156	315	244
Total	3,115	3,138	18,587	19,418	32,015	33,098
Weather-Normalized Sales Growth			TTM			
Residential			0.41%			
Commercial			1.70%			
Industrial			-1.75%			
Municipal			-1.98%			
Other			-0.97%			
Total			-0.17%			

	Current Month		YTD		Full Year	
Margins ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Electric Margins[2]	$184	$190	$1,061	$1,108	$1,862	$1,948
Gas Margins	$9	$10	$106	$109	$178	$183
Capital Expenditures ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Total[2]	$96	$90	$441	$558	$1,071	$1,107
O&M ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
O&M – Management View[2] [3]	$54	$61	$401	$425	$717	$749
O&M – GAAP View[2] [4]	$65	$72	$464	$490	$826	$864
Head Count	Actual	Budget	Actual	Budget	Forecast	Budget
Full-time Employees	3,473	3,613	3,473	3,613	3,561	3,591
Other Metrics	Actual	PY	Actual	PY	Forecast	PY
Environmental Events	2	3	5	3	N/A	3
NERC Possible Violations[5]	0	0	4	1	N/A	5

	TTM	Full Year	
Financial Metrics	Actual	Forecast	Budget
Utility ROE[6]	9.8%	9.6%	9.8%
Average Utility Capitalization ($ millions)	$8,911	$9,030	$9,174

Variance Explanations

Lower MTD ECR margins of $1 million due to lower rate base and cost of capital along with rate case outcome relative to filed position including $4 million of lower revenues offset by lower depreciation and O&M.

Lower YTD margins primarily due to lower sales volumes resulting in lower retail electric base energy and demand revenue of $40 million, lower retail rate mechanism revenue of $6 million, lower gas margins of $3 million and rate case outcome relative to filed position.

Lower MTD O&M primarily due to lower labor and burdens of $2 million, lower maintenance and materials of $2 million and the rate case outcome relative to filed position.

Lower YTD O&M primarily due to lower outside service expense of $8 million, lower storm and vegetation management expenses of $5 million, lower plant maintenance of $4 million, lower labor and burdens of $4 million and the rate case outcome relative to filed position.

(1) Full year forecast amount shown represents target.

(2) Includes net impact of approved rate case outcome for deferred AMS Capital and O&M expenses, lower depreciation expense and the offsetting revenue reduction included in margins.

(3) Net of cost recovery mechanisms and variable costs of production.

(4) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses

(5) The possible violation issues for YTD Actual is believed to be minimal risk.

(6) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Major Developments

In the recent EEI 2016 Reliability Benchmarking Survey, LKE's Electric Distribution Operations achieved a top quartile performance for System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI) metrics, and a second quartile ranking for System Average Interruption Frequency Index (SAIFI). LKE's SAIDI represented its lowest figure over the last ten years, and CAIDI was its lowest metric since 2010. Through July of this year, LKE's SAIDI, CAIDI and SAIFI reliability metrics are favorable compared to 2016.

LKE was recognized during the Kentucky Gas Association and Southern Gas Association ("SGA") annual conferences. Gas Operations was honored with the Kentucky Gas Association Accident Prevention Award for Excellence in Safety for having a zero DART rate, which represented the lowest rate among peer companies and groups. This achievement marks the 18th consecutive year LKE has captured the award. The Company's 2016 Summer Stretch video, "Dig Safety: Dig Safely," also won the SGA Safety Excellence Video Award.

The contract between KU and the USW was ratified after weeks of negotiations. The new contract period extends from August 1, 2017 through August 1, 2020. A one-year wage re-opener between KU and the IBEW was also negotiated and ratified. Among other things, the USW contract calls for annual wage increases of 3%, 2% and 2%. The IBEW wage increase was set at 3%. These increases are consistent with the assumptions included in our recent rate case award.

Old Dominion Power Company (KU's operational unit in Virginia) filed a notice of intent with the Virginia State Corporation Commission to increase its rates. The amount of the request is not included in the notice of intent but we expect to seek an additional $6 million in annual revenues (about a 9% increase).

Significant Future Events

Old Dominion Power Company (KU's operational unit in Virginia) plans to file for its rate increase on September 29, 2017, with rates expected to become effective July 1, 2018, pending approval from the Commission.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — July 2017

($ Millions)

	MTD Actual	MTD Budget	MTD Variance	Comments
Revenues:				
Electric Revenues	$ 280	$ 294	$ (14)	Due primarily to lower fuel revenues, lower ECR revenues and lower than budgeted rate case revenues including the rate case outcome relative to filed position with lower offsetting depreciation and O&M.
Gas Revenues	14	13	1	
Total Revenues	294	306	(13)	
Cost of Sales:				
Fuel Electric Costs	75	78	3	
Gas Supply Expenses	4	3	(2)	
Purchased Power	5	6	1	
Other Electric Cost of Production	3	4	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	7	8	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	9	4	
Total Cost of Sales	100	107	7	
Gross Margin:				
Electric Margin	184	190	(6)	See explanations above.
Gas Margin	9	10	(0)	
Total Gross Margin	194	200	(6)	
Operating Expenses:				
O&M	54	61	6	Primarily due to lower outside service expense, lower maintenance, lower storm and vegetation management expenses, lower labor and burdens, lower uncollectible expense and other smaller variances.
Depreciation & Amortization	33	35	3	
Taxes, Other than Income	5	5	(0)	
Equity in Earnings	0	0	0	
Other income (expense)	0	(0)	0	
EBIT	101	98	3	
Interest Expense	18	18	0	
Income from Ongoing Operations before income taxes	84	80	3	
Income Tax Expense	32	31	(1)	
Net Income (loss) from ongoing operations	**52**	**49**	**2**	
Special Item - EEI	0	0	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 52	$ 49	$ 2	
KY Regulated Financing Costs	(3)	$ (3)	(0)	
KY Regulated Net Income	$ 49	$ 47	$ 2	
Earnings Per Share - Ongoing	$ 0.07	$ 0.07	$ 0.00	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated
July 2017

($ Millions)

	YTD Actual	YTD Budget	YTD Variance	Comments
Revenues:				
Electric Revenues	$ 1,641	$ 1,725	$ (84)	Due primarily to lower sales volumes as a result of mild weather and lower than budgeted rate case revenues.
Gas Revenues	186	213	(27)	Due primarily to lower sales volumes driven by mild weather in Q1.
Total Revenues	1,827	1,937	(111)	
Cost of Sales:				
Fuel Electric Costs	450	479	29	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	73	96	23	Due primarily to lower gas usage as a result of mild weather.
Purchased Power	33	35	2	
Other Electric Cost of Production	21	24	3	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	42	41	(1)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	41	46	5	Primarily due to lower depreciation rates.
Total Cost of Sales	660	721	61	
Gross Margin:				
Electric Margin	1,061	1,108	(47)	See explanations above.
Gas Margin	106	109	(3)	
Total Gross Margin	1,167	1,216	(49)	
Operating Expenses:				
O&M	401	425	24	Primarily due to lower outside service expense, lower maintenance, lower storm and vegetation management expenses, lower labor and burdens, lower uncollectible expense and other smaller variances.
Depreciation & Amortization	211	216	5	Primarily due to lower actual capital spend and closings and the impact of the settled versus as filed depreciation rates.
Taxes, Other than Income	34	35	1	
Other income (expense)	(6)	(5)	(1)	
EBIT	515	536	(21)	
Interest Expense	125	125	(1)	
Income from Ongoing Operations before income taxes	390	411	(21)	
Income Tax Expense	148	157	9	
Net Income (loss) from ongoing operations	**242**	**254**	**(12)**	
Special Item - EEI	(1)	0	(1)	
Discontinued Operations	0	0	0	
Net Income (loss)	$ 242	$ 254	$ (13)	
KY Regulated Financing Costs	(18)	(17)	(0)	
KY Regulated Net Income	224	$ 237	$ (13)	
Earnings Per Share - Ongoing	$ 0.33	$ 0.34	$ (0.02)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E — July 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 662	$ 683	$ (20)	Due primarily to lower sales volumes as a result of mild weather and lower than budgeted rate case revenues.
Gas Revenues	186	213	(27)	Due primarily to lower sales volumes driven by mild weather in Q1.
Total Revenues	848	895	(47)	
Cost of Sales:				
Fuel Electric Costs	181	181	0	
Gas Supply Expenses	73	96	23	Due primarily to lower gas usage as a result of mild weather.
Purchased Power	28	33	5	Lower intercompany and market purchases driven by mild weather.
Other Electric Cost of Production	7	9	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	16	16	0	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	22	24	3	
Total Cost of Sales	328	360	32	
Gross Margin:				
Electric Margin	415	427	(12)	See explanations above.
Gas Margin	106	109	(3)	
Total Gross Margin	520	535	(15)	
Operating Expenses:				
O&M	177	191	13	Primarily due to lower outside service expense, lower maintenance, lower storm and vegetation management expenses, lower labor and burdens, lower uncollectible expense, and other smaller variances.
Depreciation & Amortization	85	87	2	
Taxes, Other than Income	17	18	1	
Other income (expense)	(3)	(2)	(0)	
EBIT	238	237	1	
Interest Expense	40	40	0	
Income from Ongoing Operations before income taxes	198	197	1	
Income Tax Expense	76	75	(0)	
Net Income (loss) from ongoing operations	**$ 122**	**$ 121**	**$ 0**	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - KU — July 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,006	$ 1,075	$ (69)	Due primarily to lower sales volumes as a result of mild weather and lower than budgeted rate case revenues.
Gas Revenues	0	0	0	
Total Revenues	1,006	1,075	(69)	
Cost of Sales:				
Fuel Electric Costs	272	300	28	Primarily due to decreased generation as a result of mild weather.
Gas Supply Expenses	0	0	0	
Purchased Power	30	33	3	
Other Electric Cost of Production	13	15	2	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	26	24	(1)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	19	21	3	
Total Cost of Sales	360	394	35	
Gross Margin:				
Electric Margin	646	681	(35)	See explanations above.
Gas Margin	0	0	0	
Total Gross Margin	646	681	(35)	
Operating Expenses:				
O&M	204	223	19	Primarily due to lower outside service expense, lower maintenance, lower storm and vegetation management expenses, lower labor and burdens, lower uncollectible expense and other smaller variances.
Depreciation & Amortization	126	128	2	
Taxes, Other than Income	17	17	0	
Other income (expense)	(2)	(3)	0	
EBIT	297	310	(13)	
Interest Expense	56	56	(0)	
Income from Ongoing Operations before income taxes	241	254	(14)	
Income Tax Expense	92	97	5	
Net Income (loss) from ongoing operations	**$ 149**	**$ 158**	**$ (9)**	

Note: Schedules may not sum due to rounding.

O&M								July 2017
($ Millions)								
	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	12	14	2	0	0	1	1	(0)
Project Engineering	0	0	0	0	-	-	0	0
Transmission	3	3	0	0	0	(0)	(0)	(0)
Energy Supply and Analysis	1	1	0	0	-	0	0	0
Electric Distribution	6	7	1	(0)	1	(0)	0	(0)
Gas Distribution	3	3	0	0	0	(0)	0	(0)
Advanced Metering System	0	1	1	0	-	0	-	(0)
Safety and Technical Training	0	0	0	(0)	(0)	0	(0)	0
Customer Services	8	9	1	0	0	0	(0)	0
SVP Operations Total	**33**	**38**	**5**	**1**	**2**	**1**	**1**	**0**
Audit Services	0	0	0	0	-	-	0	0
Controller	1	1	0	0	-	0	0	(0)
Supply Chain	0	0	0	0	-	0	0	0
Treasurer	2	2	0	0	-	-	(0)	0
State Regulation and Rates	0	1	0	0	-	0	0	0
Other	0	0	0	0	-	0	(0)	0
Chief Financial Officer Total	**4**	**4**	**0**	**0**	**-**	**0**	**0**	**0**
General Counsel	**2**	**2**	**0**	**0**	**0**	**0**	**(0)**	**0**
Human Resources	**0**	**1**	**0**	**0**	**-**	**0**	**0**	**0**
Information Technology	**4**	**5**	**1**	**1**	**(0)**	**0**	**0**	**0**
Corporate	**9**	**9**	**(0)**	**(0)**	**0**	**0**	**(0)**	**0**
Enterprise Security	**0**	**0**	**(0)**	**(0)**	**-**	**-**	**0**	**0**
Utility Total	**52**	**59**	**7**	**2**	**2**	**1**	**1**	**1**
Nonutility Total	**2**	**2**	**(0)**	**0**	**(0)**	**(0)**	**0**	**(0)**
O&M Total MTD	**54**	**61**	**6**	**2**	**2**	**1**	**1**	**0**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	109	120	11	3	(0)	3	7	(1)
Project Engineering	0	0	0	0	-	(0)	0	0
Transmission	18	20	2	0	0	2	(0)	0
Energy Supply and Analysis	7	7	0	0	-	0	0	0
Electric Distribution	39	45	5	(0)	7	(2)	1	0
Gas Distribution	20	20	(0)	0	(0)	(0)	0	(0)
Advanced Metering System	0	1	1	0	-	0	-	(0)
Safety and Technical Training	3	3	(0)	(0)	(0)	(0)	(0)	0
Customer Services	53	56	3	0	1	1	0	1
SVP Operations Total	**249**	**272**	**22**	**3**	**8**	**3**	**8**	**0**
Audit Services	1	1	0	0	-	0	0	0
Controller	5	5	0	(0)	(0)	0	0	0
Supply Chain	2	2	0	0	(0)	(0)	0	0
Treasurer	14	14	0	(0)	-	(0)	0	0
State Regulation and Rates	2	2	0	(0)	-	0	0	0
Other	1	1	0	0	-	0	0	(0)
Chief Financial Officer Total	**26**	**26**	**1**	**(0)**	**(0)**	**0**	**0**	**1**
General Counsel	**15**	**17**	**2**	**0**	**0**	**1**	**(0)**	**1**
Human Resources	**4**	**4**	**1**	**0**	**(0)**	**0**	**(0)**	**0**
Information Technology	**30**	**32**	**2**	**1**	**(0)**	**1**	**(0)**	**0**
Corporate	**56**	**61**	**4**	**4**	**0**	**0**	**(0)**	**(0)**
Enterprise Security	**1**	**2**	**0**	**(0)**	**-**	**0**	**0**	**0**
Utility Total	**382**	**414**	**32**	**8**	**8**	**6**	**8**	**2**
Nonutility Total	**19**	**11**	**(8)**	**(4)**	**(0)**	**(1)**	**(0)**	**(3)**
O&M Total YTD	**401**	**425**	**24**	**4**	**8**	**5**	**8**	**(1)**

Note: Schedules may not sum due to rounding.

Financing Activities — July 2017

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance
PCB			
Beg Bal	$ 898.8	$ 898.8	$ 0.0
End Bal	900.1	898.7	(1.4)
Ave Bal	**$ 899.4**	**$ 898.8**	**$ (0.7)**
Interest Exp	**$ 9.1**	**$ 7.0**	**$ (2.0)**
Rate	**1.71%**	**1.33%**	**-0.38%**
FMB/Sr Nts/Loan with PPL			
Beg Bal	$ 4,210.0	$ 4,210.0	$ 0.0
End Bal	4,210.0	4,245.0	35.0
Ave Bal	**$ 4,210.0**	**$ 4,227.5**	**$ 17.50**
Interest Exp	**$ 107.3**	**$ 107.7**	**$ 0.5**
Rate	**4.33%**	**4.33%**	**0.00%**
Short-term Debt			
Beg Bal	$ 348.1	$ 509.7	$ 161.6
End Bal	399.9	559.4	159.5
Ave Bal [(1)]	**$ 374.0**	**$ 534.5**	**$ 160.6**
Interest Exp	**$ 3.2**	**$ 3.8**	**$ 0.7**
Rate	**1.71%**	**1.21%**	**-0.49%**
Unamortized Debt Expense Bonds			
Beg Bal	$ (44.0)	$ (43.2)	$ 0.7
End Bal	(43.1)	(41.4)	1.7
Ave Bal	**$ (43.5)**	**$ (42.3)**	**$ 1.2**
Total End Bal	**$ 5,466.9**	**$ 5,661.7**	**$ 194.8**
Total Average Bal	**$ 5,380.8**	**$ 5,618.5**	**$ 237.6**
Total Expense Excl I/C [(2)]	**$ 125.4**	**$ 124.8**	**$ (0.6)**
Rate	**3.93%**	**3.74%**	**-0.18%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use the average of the beginning and ending balances.
(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed[(3)]	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 151		$ 149
LG&E	500	225		275
KU	598	24	$ 198	376
TOTAL	$ 1,398	$ 400	$ 198	$ 800

(3) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2017 Actual YTD	LKE 2017 Budget YTD	LG&E 2017 Actual YTD	LG&E 2017 Budget YTD	KU 2017 Actual YTD	KU 2017 Budget YTD
CFO pre-WC / Debt	19%	18%	27%	27%	25%	27%
CFO pre-WC + Interest / Interest	5.8	5.8	8.0	8.2	7.2	7.8
CFO pre-WC - Dividends / Debt	12%	12%	18%	22%	15%	18%
Debt to Capitalization[2]	47%	48%	38%	38%	37%	38%

Credit Metrics Moody's	LKE 2017 BP 2018	LKE 2017 BP 2019	LG&E 2017 BP 2018	LG&E 2017 BP 2019	KU 2017 BP 2018	KU 2017 BP 2019
CFO pre-WC / Debt	18%	18%	27%	29%	26%	26%
CFO pre-WC + Interest / Interest	6.0	5.7	8.5	8.7	7.8	7.6
CFO pre-WC - Dividends / Debt	11%	15%	25%	22%	20%	18%
Debt to Capitalization[2]	50%	49%	38%	36%	37%	37%

(1) Actuals represent a trailing 12 months.
(2) For LG&E and KU this excludes purchase accounting adjustments and corresponding goodwill.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2016	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.
Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — July 2017

($ Millions)

	7/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 31	$ 17	$ 15	Primarily related to reclass between Accounts Payable and funding accounts.
Accounts Receivable (Trade)	416	425	(9)	
Inventory	257	239	18	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	19	20	(1)	
Prepayments and other current assets	86	41	44	Primarily due to accounts receivable related to refined coal.
Total Current Assets	809	742	67	
Property, Plant, and Equipment	11,688	11,887	(199)	
Intangible Assets	90	92	(2)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	831	919	(88)	Primarily due to MTM adjustment of Swaps, a pension funded status adjustment due to change in discount rate decrease in ARO balance.
Goodwill	997	997	0	
Other Long-term Assets	78	81	(2)	
Total Assets	**$ 14,494**	**$ 14,718**	**$ (224)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 268	$ 219	$ 49	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	57	55	2	
Derivative Liability	5	6	(1)	
Accrued Taxes	76	53	23	Budget assumed higher Q2 tax settlement to occur in April 2017.
Regulatory Liabilities Current	17	20	(3)	
Other Current Liabilities	223	205	18	
Total Current Liabilities	646	558	88	
Debt - Affiliated Company	551	681	(130)	Used tax settlements and dividends from utilities to pay down CEP reserves.
Debt [(1)]	4,916	4,981	(65)	
Total Debt	5,467	5,662	(195)	
Deferred Tax Liabilities	1,823	1,828	(5)	
Investment Tax Credit	130	130	1	
Accum Provision for Pension & Related Benefits	347	410	(63)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	292	360	(69)	Primarily due to ARO revaluation and reclassification from long term to current.
Regulatory Liabilities Non Current	903	855	48	
Derivative Liability	25	29	(5)	
Other Liabilities	178	188	(9)	
Total Deferred Credits and Other Liabilities	3,699	3,800	(102)	
Equity	4,682	4,698	(15)	
Total Liabilities and Equity	**$ 14,494**	**$ 14,718**	**$ (224)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

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Balance Sheet - LG&E — July 2017

($ Millions)

	7/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 13	$ 5	$ 8	
Accounts Receivable (Trade)	183	182	1	
Inventory	115	107	8	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	11	5	6	
Prepayments and other current assets	65	48	17	Primarily due to timing of accounts receivable and accounts receivable from associated companies.
Total Current Assets	386	346	39	
Property, Plant, and Equipment	5,088	5,169	(80)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	449	495	(46)	
Goodwill	0	0	0	
Other Long-term Assets	15	21	(5)	
Total Assets	**$ 5,945**	**$ 6,038**	**$ (93)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 165	$ 153	$ 12	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	27	26	1	
Derivative Liability	5	6	(1)	
Accrued Taxes	35	33	2	
Regulatory Liabilities Current	7	3	4	
Other Current Liabilities	78	89	(11)	Primarily due to ARO reclassification from current to long term.
Total Current Liabilities	316	311	5	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	1,843	1,863	(20)	
Total Debt	1,843	1,863	(20)	
Deferred Tax Liabilities	1,033	1,035	(2)	
Investment Tax Credit	36	36	(0)	
Accum Provision for Pension & Related Benefits	50	73	(23)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	102	98	4	
Regulatory Liabilities Non Current	369	345	24	
Derivative Liability	25	29	(5)	
Other Liabilities	85	90	(5)	
Total Deferred Credits and Other Liabilities	1,700	1,707	(6)	
Equity	2,086	2,158	(71)	
Total Liabilities and Equity	**$ 5,945**	**$ 6,038**	**$ (93)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

Balance Sheet - KU

July 2017

($ Millions)

	7/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 18	$ 5	$ 13	Primarily related to reclass between Accounts Payable and funding accounts.
Accounts Receivable (Trade)	232	242	(9)	
Inventory	142	132	10	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	9	16	(7)	
Prepayments and other current assets	53	24	29	Primarily due to accounts receivable related to refined coal.
Total Current Assets	454	418	36	
Property, Plant, and Equipment	6,592	6,710	(118)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	380	424	(44)	Primarily due to a pension funded status adjustment due to change in discount rate and decrease in ARO balance.
Goodwill	0	0	0	
Other Long-term Assets	60	57	3	
Total Assets	**$ 7,498**	**$ 7,622**	**$ (123)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 150	$ 109	$ 41	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	30	28	1	
Derivative Liability	0	0	0	
Accrued Taxes	36	29	7	
Regulatory Liabilities Current	10	17	(6)	
Other Current Liabilities	98	71	27	Primarily due to ARO reclassification from long term to current.
Total Current Liabilities	324	254	70	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,350	2,394	(45)	
Total Debt	2,350	2,394	(45)	
Deferred Tax Liabilities	1,242	1,283	(41)	
Investment Tax Credit	95	94	1	
Accum Provision for Pension & Related Benefits	39	66	(27)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	189	262	(73)	Primarily due to ARO revaluation and reclassification from long term to current.
Regulatory Liabilities Non Current	463	437	26	
Derivative Liability	0	0	0	
Other Liabilities	42	48	(6)	
Total Deferred Credits and Other Liabilities	2,070	2,191	(121)	
Equity	2,756	2,783	(27)	
Total Liabilities and Equity	**$ 7,498**	**$ 7,622**	**$ (123)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding.

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Performance Report

August 2017

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Kentucky Regulated Dashboard — August 2017

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees[1]	0.37	2.59	1.04	1.08	1.35	1.12
Employee lost-time incidents	0	1	6	3	9	5
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,030	3,361	22,124	23,560	32,989	34,425
Utility EFOR	2.9%	5.0%	3.7%	5.0%	N/A	5.0%
Utility EAF	97.2%	92.5%	86.4%	87.3%	N/A	85.2%
Steam Fleet Commercial Availability	98.7%	93.0%	94.9%	93.0%	N/A	93.0%
Combined SAIFI	0.07	0.09	0.60	0.75	N/A	1.03
Combined SAIDI (minutes)	5.33	8.08	54.98	70.07	N/A	93.20
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	939	1,097	6,845	7,433	10,042	10,668
Commercial	746	759	5,281	5,349	7,791	7,882
Industrial	838	888	6,167	6,524	9,202	9,706
Municipals	164	177	1,194	1,274	1,759	1,846
Other	263	255	1,822	1,857	2,738	2,753
Off-System Sales	4	19	231	175	300	244
Total	2,953	3,194	21,540	22,612	31,832	33,098
Weather-Normalized Sales Growth			**TTM**			
Residential			0.59%			
Commercial			0.75%			
Industrial			-2.17%			
Municipal			-2.26%			
Other			-1.93%			
Total			-0.56%			

	Current Month		YTD		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins[2]	$175	$192	$1,236	$1,300	$1,855	$1,948
Gas Margins	$10	$10	$115	$118	$178	$183
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total[2]	$99	$96	$540	$655	$1,062	$1,107
O&M ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
O&M – Management View[2] [3]	$55	$63	$456	$488	$715	$749
O&M – GAAP View[2] [4]	$65	$74	$529	$564	$823	$864
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,466	3,614	3,466	3,614	3,540	3,591
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	5	3	N/A	3
NERC Possible Violations[5]	2	0	6	1	N/A	5

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
Utility ROE[6]	9.7%	9.5%	9.8%
Average Utility Capitalization ($ millions)	$8,913	$9,012	$9,174

Variance Explanations

Lower MTD margins primarily due to lower sales volumes from unseasonably mild weather, resulting in lower retail electric base energy and demand revenue of $12 million, and other margin components.

Lower YTD margins primarily due to lower sales volumes from unfavorable weather, resulting in lower retail electric base energy and demand revenue of $51 million, lower ECR revenue of $7 million, lower gas margins of $3 million and other offsetting margin components.

Lower MTD O&M primarily due to lower labor and burdens of $4 million and lower outside service expense of $3 million.

Lower YTD O&M primarily due to lower outside service expense of $9 million, lower labor and burdens of $8 million, lower storm and vegetation management expenses of $6 million, lower plant maintenance of $3 million and lower materials of $4 million.

(1) Full year forecast amount shown represents target.
(2) Includes net impact of approved rate case outcome for deferred AMS Capital and O&M expenses, lower depreciation expense and the offsetting revenue reduction included in margins.
(3) Net of cost recovery mechanisms and variable costs of production.
(4) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses
(5) The possible violation issues for YTD Actual is believed to be minimal risk.
(6) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Major Developments

LKE's service territory continues to be adversely impacted by unseasonably mild weather in the region. The first eight months of 2017 have been the worst for temperature-driven load in the 20-year history used for weather normalization purposes. The probability of the cumulative degree day count experienced for this eight month period is .41%. Four of the eight months were more than one standard deviation on the negative side of expected temperatures with three of those months being January, February and August, historically our highest sales months.

LKE completed the traditionally hazardous "Summer Stretch" (June 1 – August 31) with only five recordable injuries excluding hearing-loss cases. This ties the lowest number of incidents during a Summer Stretch since LKE began its strategic focus on summer safety. There were also no employee injuries during the month of August.

The Business First newspaper announced that the Company has earned a "Partners in Philanthropy Award" for being an outstanding corporate citizen. LKE moved up one spot to a fourth-place ranking in the large-company category. LKE has been ranked among the top 5 business philanthropists in the region each year since it began competing for the designation in 2012. The Company also received an "Innovative Partnership Award" for our efforts to transform a run-down urban lot into a greenspace which the community can enjoy.

LKE once again has been named as one of the top 10 utilities in economic development by Site Selection magazine. This marks the eighth year the Company has received this honor since 2000.

As part of the Company's participation in mutual assistance organizations, LKE has released support personnel to various states to assist with hurricane restoration efforts. More than 50 of LKE's contractors were dispatched to Texas supporting American Electric Power's Hurricane Harvey restoration efforts. These resources have been redeployed to Florida to be a part of the over 400 LKE employee and contractor support personnel which are assisting Duke Energy Florida and Florida Power & Light with Hurricane Irma.

Significant Future Events

Old Dominion Power Company (KU's operational unit in Virginia) plans to file for its rate increase on September 29, 2017, with rates expected to become effective July 1, 2018, pending approval from the Virginia State Corporation Commission.

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Income Statement: Actual vs. Budget (Month) - LKE Consolidated

August 2017

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 263	$ 298	$ (35)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	13	13	0	
Total Revenues	276	310	(35)	
Cost of Sales:				
Fuel Electric Costs	69	80	11	Primarily due to decreased generation as a result of unfavorable weather.
Gas Supply Expenses	3	2	(0)	
Purchased Power	5	6	1	
Other Electric Cost of Production	3	4	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	7	7	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	9	4	
Total Cost of Sales	91	108	17	
Gross Margin:				
Electric Margin	175	192	(18)	See explanations above.
Gas Margin	10	10	(0)	
Total Gross Margin	184	202	(18)	
O&M	55	63	9	Primarily due to lower labor and burdens and lower outside service expense.
Depreciation & Amortization	33	35	3	
Taxes, Other than Income	5	5	0	
Other income (expense)	(0)	(0)	0	
EBIT	92	98	(6)	
Interest Expense	18	18	0	
Income from Ongoing Operations before income taxes	74	80	(6)	
Income Tax Expense	28	31	3	
Net Income (loss) from ongoing operations	**46**	**49**	**(3)**	
Special Item - EEI	0	0	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 46	$ 49	$ (3)	
KY Regulated Financing Costs	(3)	$ (3)	(0)	
KY Regulated Net Income	$ 44	$ 47	$ (3)	
Earnings Per Share - Ongoing	$ 0.06	$ 0.07	$ (0.00)	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — August 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,904	$ 2,022	$ (119)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	199	225	(27)	Due primarily to lower sales volumes driven by unfavorable weather in Q1.
Total Revenues	2,102	2,248	(146)	
Cost of Sales:				
Fuel Electric Costs	519	559	40	Primarily due to decreased generation as a result of unfavorable weather.
Gas Supply Expenses	75	98	23	Due primarily to lower gas usage as a result of unfavorable weather.
Purchased Power	38	41	3	
Other Electric Cost of Production	24	28	4	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	49	48	(1)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	46	55	9	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates which is offset in margins.
Total Cost of Sales	751	829	78	
Gross Margin:				
Electric Margin	1,236	1,300	(65)	See explanations above.
Gas Margin	115	118	(3)	
Total Gross Margin	1,351	1,419	(67)	
O&M	456	488	33	Primarily due to lower outside service expense, lower labor and burdens, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	244	251	8	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates which is offset in margins.
Taxes, Other than Income	39	40	1	
Other income (expense)	(6)	(5)	(1)	
EBIT	607	634	(27)	
Interest Expense	143	143	(1)	
Income from Ongoing Operations before income taxes	463	491	(27)	
Income Tax Expense	175	188	12	
Net Income (loss) from ongoing operations	**288**	**303**	**(15)**	
Special Item - EEI	(1)	0	(1)	
Discontinued Operations	0	0	0	
Net Income (loss)	$ 288	$ 303	$ (16)	
KY Regulated Financing Costs	(20)	(20)	(0)	
KY Regulated Net Income	268	$ 283	$ (16)	
Earnings Per Share - Ongoing	$ 0.39	$ 0.41	$ (0.02)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E — August 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 771	$ 808	$ (37)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	199	225	(27)	Due primarily to lower sales volumes driven by unfavorable weather in Q1.
Total Revenues	969	1033	(64)	
Cost of Sales:				
Fuel Electric Costs	207	212	4	
Gas Supply Expenses	75	98	23	Due primarily to lower gas usage as a result of unfavorable weather.
Purchased Power	32	38	6	Lower intercompany and market purchases driven by unfavorable weather.
Other Electric Cost of Production	9	10	2	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	19	20	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	24	29	4	
Total Cost of Sales	366	407	40	
Gross Margin:				
Electric Margin	488	508	(21)	See explanations above.
Gas Margin	115	118	(3)	
Total Gross Margin	603	627	(24)	
O&M	203	220	17	Primarily due to lower outside service expense, lower non labor maintenance, lower non labor storm and vegetation management expenses and lower labor and burdens.
Depreciation & Amortization	98	102	4	
Taxes, Other than Income	20	20	1	
Other income (expense)	(3)	(2)	(0)	
EBIT	280	282	(3)	
Interest Expense	46	46	(0)	
Income from Ongoing Operations before income taxes	234	236	(3)	
Income Tax Expense	89	91	1	
Net Income (loss) from ongoing operations	**$ 144**	**$ 146**	**$ (1)**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Actual vs. Budget (YTD) - KU

August 2017

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 1,161	$ 1,252	$ (90)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	0	0	0	
Total Revenues	1,161	1,252	(90)	
Cost of Sales:				
Fuel Electric Costs	315	350	36	Primarily due to decreased generation as a result of unfavorable weather.
Gas Supply Expenses	0	0	0	
Purchased Power	32	36	4	
Other Electric Cost of Production	15	18	3	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	30	29	(1)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	22	26	5	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates which is offset in margins.
Total Cost of Sales	413	460	46	
Gross Margin:				
Electric Margin	748	792	(44)	See explanations above.
Gas Margin	0	0	0	
Total Gross Margin	748	792	(44)	
O&M	232	256	23	Primarily due to lower outside service expense, lower non labor maintenance, Power Production non labor operations, lower storm and vegetation management expenses, lower labor and burdens, lower uncollectible expense and other smaller variances.
Depreciation & Amortization	145	149	4	
Taxes, Other than Income	20	20	0	
Other income (expense)	(2)	(3)	0	
EBIT	349	365	(16)	
Interest Expense	64	64	(0)	
Income from Ongoing Operations before income taxes	284	301	(16)	
Income Tax Expense	108	114	6	
Net Income (loss) from ongoing operations	**$ 176**	**$ 186**	**$ (10)**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

O&M — August 2017

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	14	15	1	1	0	0	1	(0)
Project Engineering	0	0	0	0	-	(0)	0	0
Transmission	2	3	0	0	0	(0)	(0)	0
Energy Supply and Analysis	1	1	0	0	-	(0)	0	0
Electric Distribution	6	7	1	0	1	(0)	0	0
Gas Distribution	3	3	0	0	(0)	0	0	0
Advanced Metering System	0	1	1	0	-	0	-	(0)
Safety and Technical Training	0	1	0	(0)	(0)	(0)	0	0
Customer Services	8	9	1	0	0	0	(0)	0
SVP Operations Total	**35**	**40**	**5**	**1**	**1**	**0**	**1**	**1**
Audit Services	0	0	0	0	-	0	(0)	0
Controller	1	1	0	0	-	0	0	0
Supply Chain	0	0	0	0	-	(0)	0	(0)
Treasurer	2	2	0	0	-	(0)	0	0
State Regulation and Rates	0	0	0	(0)	-	0	(0)	0
Other	0	0	0	0	-	0	0	(0)
Chief Financial Officer Total	**4**	**4**	**0**	**0**	**-**	**0**	**0**	**0**
General Counsel	**2**	**3**	**1**	**0**	**0**	**1**	**0**	**0**
Human Resources	**1**	**1**	**0**	**0**	**-**	**0**	**0**	**(0)**
Information Technology	**4**	**5**	**1**	**0**	**(0)**	**0**	**0**	**0**
Corporate	**7**	**9**	**2**	**2**	**0**	**0**	**(0)**	**0**
Enterprise Security	**0**	**0**	**0**	**0**	**-**	**0**	**0**	**(0)**
Utility Total	**53**	**62**	**9**	**4**	**1**	**1**	**1**	**1**
Nonutility Total	**2**	**2**	**0**	**0**	**(0)**	**(0)**	**0**	**(0)**
O&M Total MTD	**55**	**63**	**9**	**4**	**1**	**1**	**1**	**1**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	123	135	12	3	(0)	3	8	(2)
Project Engineering	0	0	0	0	-	(0)	0	0
Transmission	20	23	2	0	0	2	(0)	0
Energy Supply and Analysis	8	8	0	0	-	(0)	0	0
Electric Distribution	45	52	6	0	8	(3)	1	0
Gas Distribution	23	23	(0)	0	(0)	0	0	(0)
Advanced Metering System	0	1	1	0	-	1	-	(0)
Safety and Technical Training	3	4	0	(0)	(0)	(0)	(0)	0
Customer Services	62	66	4	0	1	1	0	2
SVP Operations Total	**285**	**312**	**27**	**4**	**9**	**4**	**9**	**1**
Audit Services	1	1	0	0	-	0	0	0
Controller	6	6	0	(0)	(0)	0	0	0
Supply Chain	3	3	0	0	(0)	(0)	0	0
Treasurer	16	16	1	(0)	-	(0)	0	1
State Regulation and Rates	2	3	0	(0)	-	0	0	0
Other	1	2	0	0	-	0	0	(0)
Chief Financial Officer Total	**29**	**30**	**1**	**0**	**(0)**	**0**	**0**	**1**
General Counsel	**17**	**20**	**3**	**1**	**0**	**1**	**(0)**	**1**
Human Resources	**4**	**5**	**1**	**0**	**(0)**	**0**	**(0)**	**0**
Information Technology	**35**	**37**	**3**	**1**	**(0)**	**1**	**(0)**	**1**
Corporate	**64**	**69**	**6**	**6**	**0**	**0**	**(0)**	**(0)**
Enterprise Security	**2**	**2**	**0**	**(0)**	**-**	**0**	**0**	**0**
Utility Total	**435**	**476**	**41**	**12**	**9**	**8**	**9**	**3**
Nonutility Total	**20**	**13**	**(8)**	**(4)**	**(0)**	**(1)**	**(0)**	**(3)**
O&M Total YTD	**456**	**488**	**33**	**8**	**9**	**6**	**9**	**0**

Note: Schedules may not sum due to rounding.

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Financing Activities — August 2017

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance
PCB			
Beg Bal	$ 898.8	$ 898.8	$ 0.0
End Bal	900.1	898.7	(1.4)
Ave Bal	**$ 899.4**	**$ 898.7**	**$ (0.7)**
Interest Exp	**$ 10.6**	**$ 8.0**	**$ (2.6)**
Rate	**1.75%**	**1.32%**	**-0.43%**
FMB/Sr Nts/Loan with PPL			
Beg Bal	$ 4,210.0	$ 4,210.0	$ 0.0
End Bal	4,210.0	4,245.0	35.0
Ave Bal	**$ 4,210.0**	**$ 4,227.5**	**$ 17.50**
Interest Exp	**$ 122.1**	**$ 123.2**	**$ 1.1**
Rate	**4.30%**	**4.32%**	**0.02%**
Short-term Debt			
Beg Bal	$ 348.1	$ 509.7	$ 161.6
End Bal	296.8	506.7	209.9
Ave Bal (1)	**$ 322.4**	**$ 508.2**	**$ 185.8**
Interest Exp	**$ 3.7**	**$ 4.4**	**$ 0.7**
Rate	**1.75%**	**1.29%**	**-0.45%**
Unamortized Debt Expense Bonds			
Beg Bal	$ (44.0)	$ (43.2)	$ 0.7
End Bal	(42.9)	(40.9)	2.0
Ave Bal	**$ (43.4)**	**$ (42.1)**	**$ 1.4**
Total End Bal	**$ 5,363.9**	**$ 5,609.5**	**$ 245.5**
Total Average Bal	**$ 5,382.0**	**$ 5,592.4**	**$ 210.4**
Total Expense Excl I/C (2)	**$ 143.3**	**$ 142.8**	**$ (0.5)**
Rate	**3.91%**	**3.75%**	**-0.16%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use the average of the beginning and ending balances.
(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(3)	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 150		$ 150
LG&E	500	147		353
KU	598	(0)	$ 198	400
TOTAL	$ 1,398	$ 297	$ 198	$ 903

(3) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics — August 2017

Credit Metrics[1] Moody's	LKE 2017 Actual YTD	LKE 2017 Budget YTD	LG&E 2017 Actual YTD	LG&E 2017 Budget YTD	KU 2017 Actual YTD	KU 2017 Budget YTD
CFO pre-WC / Debt	19%	19%	28%	27%	26%	28%
CFO pre-WC + Interest / Interest	6.1	5.9	8.1	8.3	7.3	7.9
CFO pre-WC - Dividends / Debt	13%	13%	20%	23%	16%	19%
Debt to Capitalization	47%	48%	35%	35%	34%	34%

Credit Metrics Moody's	LKE 2017 BP 2018	LKE 2017 BP 2019	LG&E 2017 BP 2018	LG&E 2017 BP 2019	KU 2017 BP 2018	KU 2017 BP 2019
CFO pre-WC / Debt	17.6%	17.9%	27%	29%	26%	26%
CFO pre-WC + Interest / Interest	6.0	5.7	8.6	8.8	7.9	7.6
CFO pre-WC - Dividends / Debt	10.5%	14.5%	25%	22%	20%	17%
Debt to Capitalization	50.5%	49.0%	35%	34%	34%	34%

(1) Actuals represent a trailing 12 months.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2016	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics. Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — August 2017

($ Millions)

	8/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 15	$ 18	$ (3)	
Accounts Receivable (Trade)	403	429	(27)	
Inventory	264	240	24	Lower fuel burn due to unfavorable weather has resulted in higher than budgeted coal inventory levels.
Regulatory Assets Current	19	22	(3)	
Prepayments and other current assets	82	39	43	Primarily due to higher accounts receivable related to refined coal, dividends receivable and other accounts receivable offset by accounts receivable from affiliates.
Total Current Assets	782	748	34	
Property, Plant, and Equipment	11,740	11,930	(189)	
Intangible Assets	89	91	(2)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	834	921	(87)	
Goodwill	997	997	0	
Other Long-term Assets	79	80	(2)	
Total Assets	**$ 14,522**	**$ 14,768**	**$ (246)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 295	$ 222	$ 73	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	98	0	98	Dividends are considered declared and paid in the same month in the budget.
Customer Deposits	57	55	2	
Derivative Liability	5	6	(1)	
Accrued Taxes	112	89	23	Budget assumed higher Q2 tax settlement to occur in April 2017.
Regulatory Liabilities Current	21	20	1	
Other Current Liabilities	248	221	26	Primarily due to ARO reclassification from long term to current and increase in accrued salaries and benefits in actuals versus the budget which assumed a static balance as of September 2017 when the budget was finalized.
Total Current Liabilities	836	613	223	
Debt - Affiliated Company	550	681	(131)	Used tax settlements and dividends from utilities to pay down CEP reserves.
Debt [(1)]	4,814	4,929	(114)	
Total Debt	5,364	5,609	(246)	
Deferred Tax Liabilities	1,819	1,828	(8)	
Investment Tax Credit	130	130	1	
Accum Provision for Pension & Related Benefits	349	410	(61)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	290	359	(69)	Primarily due to ARO revaluation and reclassification from long term to current.
Regulatory Liabilities Non Current	898	854	45	
Derivative Liability	26	29	(3)	
Other Liabilities	178	188	(10)	
Total Deferred Credits and Other Liabilities	3,691	3,797	(106)	
Equity	4,631	4,748	(117)	
Total Liabilities and Equity	**$ 14,522**	**$ 14,768**	**$ (246)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

August 2017

($ Millions)

	8/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 6	$ 5	$ 0	
Accounts Receivable (Trade)	175	183	(9)	
Inventory	123	112	11	Lower fuel burn due to unfavorable weather has resulted in higher than budgeted coal inventory levels.
Regulatory Assets Current	11	5	6	
Prepayments and other current assets	55	47	8	
Total Current Assets	369	353	17	
Property, Plant, and Equipment	5,120	5,197	(78)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	451	494	(43)	
Goodwill	0	0	0	
Other Long-term Assets	15	21	(6)	
Total Assets	**$ 5,962**	**$ 6,071**	**$ (110)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 182	$ 155	$ 27	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	28	25	3	
Customer Deposits	27	26	1	
Derivative Liability	5	6	(1)	
Accrued Taxes	51	51	(0)	
Regulatory Liabilities Current	9	3	6	
Other Current Liabilities	89	93	(4)	
Total Current Liabilities	390	360	30	
Debt - Affiliated Company	30	0	30	Increase due to notes payable to KU.
Debt [1]	1,765	1,852	(88)	
Total Debt	1,795	1,852	(58)	
Deferred Tax Liabilities	1,033	1,035	(2)	
Investment Tax Credit	36	36	(0)	
Accum Provision for Pension & Related Benefits	50	72	(22)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	101	97	4	
Regulatory Liabilities Non Current	365	344	22	
Derivative Liability	26	29	(3)	
Other Liabilities	85	90	(5)	
Total Deferred Credits and Other Liabilities	1,696	1,703	(7)	
Equity	2,081	2,156	(76)	
Total Liabilities and Equity	**$ 5,962**	**$ 6,071**	**$ (110)**	

[1] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments.

Case Nos. 2018-00294 and 2018-00295
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Balance Sheet - KU

August 2017

($ Millions)

	8/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 9	$ 5	$ 4	
Accounts Receivable (Trade)	227	245	(18)	
Inventory	140	128	13	Lower fuel burn due to unfavorable weather has resulted in higher than budgeted coal inventory levels
Regulatory Assets Current	8	17	(9)	
Prepayments and other current assets	79	22	56	Primarily due to accounts receivable related to refined coal and notes receivable from LG&E.
Total Current Assets	464	417	46	
Property, Plant, and Equipment	6,612	6,724	(112)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	381	427	(46)	Primarily due to a pension funded status adjustment and decrease in ARO balance.
Goodwill	0	0	0	
Other Long-term Assets	61	57	4	
Total Assets	**$ 7,530**	**$ 7,638**	**$ (108)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 148	$ 110	$ 39	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	61	33	28	In the budget dividends are calculated in the month declared and any excess dividends are not recognized until the subsequent month due to balancing within the budget system.
Customer Deposits	30	28	2	
Derivative Liability	0	0	0	
Accrued Taxes	55	49	6	
Regulatory Liabilities Current	12	17	(4)	
Other Current Liabilities	107	78	28	Primarily due to ARO reclassification from long term to current.
Total Current Liabilities	413	315	98	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,326	2,353	(27)	
Total Debt	2,326	2,353	(27)	
Deferred Tax Liabilities	1,242	1,283	(41)	
Investment Tax Credit	95	94	1	
Accum Provision for Pension & Related Benefits	39	66	(27)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	189	262	(73)	Primarily due to ARO revaluation and reclassification from long term to current.
Regulatory Liabilities Non Current	463	438	25	
Derivative Liability	0	0	0	
Other Liabilities	42	49	(6)	
Total Deferred Credits and Other Liabilities	2,070	2,191	(122)	
Equity	2,721	2,779	(57)	
Total Liabilities and Equity	**$ 7,530**	**$ 7,638**	**$ (108)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments.

Performance Report

September 2017

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Kentucky Regulated Dashboard — September 2017

	Current Month		YTD		Full Year	
Safety	Actual	PY	Actual	PY	Forecast	PY
TCIR - Employees[1]	1.11	1.39	1.05	1.13	1.35	1.12
Employee lost-time incidents	2	0	8	3	10	5
Reliability	Actual	Budget	Actual	Budget	Forecast	Budget
Generation Volumes	2,628	2,702	24,751	26,261	32,915	34,425
Utility EFOR	1.8%	5.0%	3.5%	5.0%	N/A	5.0%
Utility EAF	94.3%	90.5%	87.4%	87.6%	N/A	85.2%
Steam Fleet Commercial Availability	99.4%	93.0%	95.4%	93.0%	N/A	93.0%
Combined SAIFI	0.06	0.07	0.66	0.83	N/A	1.03
Combined SAIDI (minutes)	5.25	5.90	60.23	75.97	N/A	93.20
GwH Sales	Actual	Budget	Actual	Budget	Forecast	Budget
Residential	702	788	7,548	8,221	9,966	10,668
Commercial	640	645	5,921	5,994	7,782	7,882
Industrial	790	767	6,958	7,291	9,250	9,706
Municipals	140	156	1,334	1,430	1,760	1,846
Other	238	219	2,059	2,077	2,749	2,753
Off-System Sales	23	22	255	197	302	244
Total	2,534	2,598	24,074	25,210	31,807	33,098
Weather-Normalized Sales Growth			TTM			
Residential			0.80%			
Commercial			0.45%			
Industrial			-1.22%			
Municipal			-2.64%			
Other			-2.53%			
Total			-0.36%			

	Current Month		YTD		Full Year	
Margins ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Electric Margins[2]	$159	$166	$1,395	$1,466	$1,855	$1,948
Gas Margins	$10	$10	$125	$128	$178	$183
Capital Expenditures ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Total[2]	$94	$106	$634	$761	$1,056	$1,107
O&M ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
O&M – Management View[2] [3]	$59	$63	$515	$551	$715	$749
O&M – GAAP View[2] [4]	$68	$73	$597	$637	$823	$864
Head Count	Actual	Budget	Actual	Budget	Forecast	Budget
Full-time Employees	3,464	3,610	3,464	3,610	3,528	3,591
Other Metrics	Actual	PY	Actual	PY	Forecast	PY
Environmental Events	0	0	5	3	N/A	3
NERC Possible Violations[5]	1	4	7	5	N/A	5

	TTM	Full Year	
Financial Metrics	Actual	Forecast	Budget
Utility ROE[6]	9.6%	9.5%	9.8%
Average Utility Capitalization ($ millions)	$8,927	$8,992	$9,174

Variance Explanations

Lower margins MTD primarily due to lower net retail electric base energy and demand revenue, lower ECR revenue and other margin components.

Lower margins YTD primarily due to lower sales volumes from unfavorable weather, resulting in lower retail electric base energy and demand revenue of $53 million, lower ECR revenue of $8 million and lower gas margins of $3 million and other offsetting margin components.

Lower O&M YTD primarily due to lower outside service expense of $10 million, lower labor and burdens of $11 million, lower storm and vegetation management expenses of $7 million, lower plant maintenance of $4 million and lower materials of $4 million.

(1) Full year forecast amount shown represents target.

(2) Includes net impact of approved rate case outcome for deferred AMS Capital and O&M expenses, lower depreciation expense and the offsetting revenue reduction included in margins.

(3) Net of cost recovery mechanisms and variable costs of production.

(4) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses

(5) The possible violation issues for YTD Actual is believed to be minimal risk.

Note: Schedules may not sum due to rounding.

Major Developments

LKE once again has been recognized among the best in the nation as it has been named one of the top Healthiest 100 Workplaces in the U.S. The winners were honored at the Fitbit Captivate Conference in Chicago for their commitment to employee health and exceptional corporate wellness programs. Thousands of companies competed for the award on a local level, with more than 400 advancing as national finalists. LKE was also honored earlier this year with the Worksite Wellness Council of Louisville's Platinum Award and the Health Champion Designation Award from the American Diabetes Association.

Old Dominion Power (KU's operational unit in Virginia) filed a request with the Virginia State Corporation Commission for an increase of $6.7 million (10 percent) in its base rates. If approved, the new rates will become effective July 1, 2018.

Significant Future Events

There are no significant future events at this time.

Case Nos. 2018-00294 and 2018-00295
Attachment to Filing Requirement
807 KAR 5:001 Sec. 16(7)(o)

Arbough

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — September 2017

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 238	$ 251	$ (13)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	12	13	(1)	
Total Revenues	250	264	(14)	
Cost of Sales:				
Fuel Electric Costs	60	62	2	
Gas Supply Expenses	2	3	0	
Purchased Power	5	5	0	
Other Electric Cost of Production	3	3	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	6	7	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	9	4	
Total Cost of Sales	81	89	7	
Gross Margin:				
Electric Margin	159	166	(7)	See explanations above.
Gas Margin	10	10	(0)	
Total Gross Margin	169	176	(7)	
O&M	59	63	4	
Depreciation & Amortization	33	36	3	
Taxes, Other than Income	5	5	(0)	
Other income (expense)	0	(0)	1	
EBIT	72	71	1	
Interest Expense	18	19	1	
Income from Ongoing Operations before income taxes	54	53	2	
Income Tax Expense	20	20	(1)	
Net Income (loss) from ongoing operations	**34**	**33**	**1**	
Special Item - EEI	0	0	0	
Discontinued Operations	0	0	0	
Net Income (loss)	$ 34	$ 33	$ 1	
KY Regulated Financing Costs	(3)	$ (2)	(0)	
KY Regulated Net Income	$ 32	$ 30	$ 1	
Earnings Per Share - Ongoing	$ 0.05	$ 0.04	$ 0.00	

Note: Schedules may not sum due to rounding.

Case Nos. 2018-00294 and 2018-00295
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Income Statement: Actual vs. Budget (YTD) - LKE Consolidated

September 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,141	$ 2,274	$ (132)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	211	238	(27)	Due primarily to lower sales volumes driven by unfavorable weather in Q1.
Total Revenues	2,352	2,512	(160)	
Cost of Sales:				
Fuel Electric Costs	578	621	42	Primarily due to decreased generation as a result of unfavorable weather.
Gas Supply Expenses	78	101	23	Due primarily to lower gas usage as a result of unfavorable weather.
Purchased Power	43	45	3	
Other Electric Cost of Production	27	31	4	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	55	55	0	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	52	65	13	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates which is offset in margins.
Total Cost of Sales	832	918	85	
Gross Margin:				
Electric Margin	1,395	1,466	(71)	See explanations above.
Gas Margin	125	128	(3)	
Total Gross Margin	1,520	1,594	(74)	
O&M	515	551	37	Primarily due to lower outside service expense, lower labor and burdens, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	276	287	11	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Taxes, Other than Income	45	46	1	
Other income (expense)	(5)	(6)	0	
EBIT	679	705	(26)	
Interest Expense	161	161	0	
Income from Ongoing Operations before income taxes	518	544	(26)	
Income Tax Expense	196	207	12	
Net Income (loss) from ongoing operations	**322**	**336**	**(14)**	
Special Item - EEI	(1)	0	(1)	
Discontinued Operations	1	0	0	
Net Income (loss)	$ 322	$ 336	$ (14)	
KY Regulated Financing Costs	(23)	(22)	(0)	
KY Regulated Net Income	300	$ 314	$ (14)	
Earnings Per Share - Ongoing	$ 0.44	$ 0.45	$ (0.02)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E — September 2017

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 869	$ 912	$ (43)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	211	238	(27)	Due primarily to lower sales volumes driven by unfavorable weather in Q1.
Total Revenues	1,080	1151	(70)	
Cost of Sales:				
Fuel Electric Costs	230	235	5	Primarily due to decreased generation as a result of unfavorable weather.
Gas Supply Expenses	78	101	23	Due primarily to lower gas usage as a result of unfavorable weather.
Purchased Power	37	43	6	Lower intercompany and market purchases driven by unfavorable weather.
Other Electric Cost of Production	10	12	2	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	21	22	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	27	33	6	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates which is offset in margins.
Total Cost of Sales	402	446	44	
Gross Margin:				
Electric Margin	553	577	(24)	See explanations above.
Gas Margin	125	128	(3)	
Total Gross Margin	678	705	(26)	
O&M	228	249	21	Primarily due to lower outside service expense, lower labor and burdens, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	111	116	5	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Taxes, Other than Income	22	23	1	
Other income (expense)	(3)	(2)	(0)	
EBIT	314	314	(0)	
Interest Expense	52	52	1	
Income from Ongoing Operations before income taxes	262	262	0	
Income Tax Expense	100	100	1	
Net Income (loss) from ongoing operations	**$ 162**	**$ 161**	**$ 1**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Actual vs. Budget (YTD) - KU — September 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,302	$ 1,402	$ (100)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	0	0	0	
Total Revenues	1,302	1,402	(100)	
Cost of Sales:				
Fuel Electric Costs	352	389	37	Primarily due to decreased generation as a result of unfavorable weather.
Gas Supply Expenses	0	0	0	
Purchased Power	33	40	6	Lower intercompany and market purchases driven by unfavorable weather.
Other Electric Cost of Production	17	20	3	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	34	33	(1)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	25	31	7	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Total Cost of Sales	461	513	52	
Gross Margin:				
Electric Margin	842	889	(48)	See explanations above.
Gas Margin	0	0	0	
Total Gross Margin	842	889	(48)	
O&M	264	289	25	Primarily due to lower outside service expense, lower labor and burdens, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	164	170	6	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Taxes, Other than Income	22	22	0	
Other income (expense)	(2)	(3)	1	
EBIT	389	405	(16)	
Interest Expense	72	72	(1)	
Income from Ongoing Operations before income taxes	317	333	(17)	
Income Tax Expense	120	127	6	
Net Income (loss) from ongoing operations	**$ 197**	**$ 207**	**$ (10)**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Forecast vs. Budget - LKE Consolidated — September 2017

($ Millions)

	Full Year Q3 Forecast	Full Year Budget	Full Year Variance	Comments
Revenues:				
Electric Revenues	$ 2,843	$ 3,017	$ (174)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	299	329	(30)	Due primarily to lower sales volumes driven by unfavorable weather in Q1.
Total Revenues	3,142	3,346	(204)	
Cost of Sales:				
Fuel Electric Costs	763	813	51	Primarily due to decreased generation as a result of unfavorable weather.
Gas Supply Expenses	112	135	24	Due primarily to lower gas usage as a result of unfavorable weather.
Purchased Power	57	60	2	
Other Electric Cost of Production	36	41	6	Due to lower than budgeted scrubber reaction ammonia expenses and the amortization of coal yard service fees.
Mechanism - ECR, DSM & GLT - Operation and Maintenance	72	74	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	69	93	23	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Total Cost of Sales	1,109	1,216	107	
Gross Margin:				
Electric Margin	1,855	1,948	(93)	See explanations above.
Gas Margin	178	183	(5)	See explanations above.
Total Gross Margin	2,033	2,130	(98)	
O&M	715	749	34	Primarily due to lower outside service expense, lower labor and burdens, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	377	395	19	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Taxes, Other than Income	60	61	1	
Other income (expense)	(7)	(8)	1	
EBIT	874	917	(44)	
Interest Expense	215	217	2	
Income from Ongoing Operations before income taxes	658	700	(42)	
Income Tax Expense	249	267	18	
Net Income (loss) from ongoing operations	**409**	**433**	**$ (24)**	
Special Item - EEI	(1)	0	(1)	
Discontinued Operations	1	(0)	1	
Net Income (loss)	$ 410	$ 433	$ (24)	
KY Regulated Financing Costs	(30)	(30)	(0)	
KY Regulated Net Income	$ 380	$ 403	$ (24)	
Earnings Per Share - Ongoing	$ 0.55	$ 0.58	$ (0.03)	

Note: Schedules may not sum due to rounding.

O&M								September 2017

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	15	17	2	1	(0)	2	1	(1)
Project Engineering	5	0	(5)	(1)	0	(4)	(0)	(1)
Transmission	3	3	1	(0)	0	0	(0)	0
Energy Supply and Analysis	1	1	0	(0)	0	(0)	(0)	0
Electric Distribution	4	6	1	0	1	(0)	0	0
Gas Distribution	3	3	0	0	0	(0)	(0)	0
Advanced Metering System	0	1	1	0	0	0	0	(0)
Safety and Technical Training	0	0	0	(0)	(0)	0	(0)	0
Customer Services	8	9	1	0	0	0	(0)	0
SVP Operations Total	**40**	**40**	**0**	**1**	**2**	**(2)**	**1**	**(2)**
Audit Services	0	0	0	0	0	0	0	0
Controller	1	1	0	0	0	(0)	0	0
Supply Chain	0	0	0	0	0	(0)	(0)	0
Treasurer	2	2	0	0	0	0	0	0
State Regulation and Rates	0	0	(0)	(0)	0	(0)	(0)	0
Other	0	0	0	0	0	(0)	0	0
Chief Financial Officer Total	**4**	**4**	**0**	**0**	**0**	**(0)**	**0**	**0**
General Counsel	**2**	**3**	**2**	**0**	**0**	**1**	**0**	**0**
Human Resources	**0**	**1**	**0**	**0**	**0**	**0**	**0**	**0**
Information Technology	**4**	**5**	**1**	**0**	**(0)**	**0**	**0**	**0**
Corporate	**7**	**9**	**2**	**2**	**0**	**0**	**(0)**	**0**
Enterprise Security	**0**	**0**	**0**	**0**	**0**	**(0)**	**0**	**0**
Utility Total	**57**	**62**	**5**	**4**	**1**	**(0)**	**1**	**(1)**
Nonutility Total	**2**	**1**	**(1)**	**(1)**	**0**	**(0)**	**(0)**	**(0)**
O&M Total MTD	**59**	**63**	**4**	**3**	**1**	**(0)**	**1**	**(1)**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	138	152	14	4	(0)	5	9	(3)
Project Engineering	6	0	(5)	(0)	0	(4)	(0)	(1)
Transmission	23	26	3	0	1	2	(0)	0
Energy Supply and Analysis	9	10	0	0	0	(0)	0	0
Electric Distribution	50	57	8	0	9	(3)	1	0
Gas Distribution	26	26	0	0	(0)	0	0	(0)
Advanced Metering System	0	2	2	1	0	1	0	(0)
Safety and Technical Training	4	4	0	(0)	(0)	(0)	(0)	0
Customer Services	70	74	5	0	1	1	0	2
SVP Operations Total	**325**	**351**	**27**	**5**	**11**	**2**	**10**	**(1)**
Audit Services	1	1	0	0	0	0	0	0
Controller	7	7	0	(0)	(0)	0	0	0
Supply Chain	3	3	0	0	(0)	(0)	0	0
Treasurer	18	18	1	(0)	0	(0)	0	1
State Regulation and Rates	3	3	0	(0)	0	0	0	0
Other	2	2	0	0	0	(0)	0	(0)
Chief Financial Officer Total	**33**	**34**	**2**	**0**	**(0)**	**0**	**0**	**1**
General Counsel	**19**	**24**	**5**	**1**	**0**	**3**	**0**	**1**
Human Resources	**5**	**5**	**1**	**0**	**(0)**	**0**	**0**	**0**
Information Technology	**39**	**42**	**3**	**1**	**(0)**	**1**	**0**	**1**
Corporate	**71**	**79**	**8**	**8**	**0**	**0**	**(0)**	**0**
Enterprise Security	**2**	**2**	**0**	**(0)**	**0**	**0**	**0**	**0**
Utility Total	**492**	**537**	**46**	**15**	**10**	**7**	**10**	**3**
Nonutility Total	**23**	**14**	**(9)**	**(5)**	**(0)**	**(1)**	**(0)**	**(3)**
O&M Total YTD	**515**	**551**	**37**	**11**	**10**	**6**	**10**	**(0)**

	Full Year							
	Forecast	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	205	217	12	5	(1)	3	9	(4)
Project Engineering	6	1	(5)	(0)	0	(4)	0	(1)
Transmission	32	34	2	0	0	1	(0)	1
Energy Supply and Analysis	13	13	0	0	0	(0)	0	0
Electric Distribution	67	74	7	(0)	8	(2)	1	0
Gas Distribution	36	35	(1)	0	(0)	(0)	(0)	(0)
Advanced Metering System	0	3	3	1	0	2	0	(0)
Safety and Technical Training	5	5	(0)	(0)	(0)	(0)	(0)	0
Customer Services	95	99	5	0	2	1	(0)	2
SVP Operations Total	**458**	**482**	**23**	**6**	**9**	**0**	**10**	**(2)**
Audit Services	2	2	0	0	0	0	0	0
Controller	9	9	(0)	(0)	(0)	(0)	0	0
Supply Chain	4	4	0	0	(0)	(0)	0	(0)
Treasurer	23	24	1	(0)	0	(0)	0	1
State Regulation and Rates	4	4	0	(0)	0	0	0	0
Other	2	2	0	1	0	(0)	0	(0)
Chief Financial Officer Total	**44**	**46**	**1**	**1**	**(0)**	**(0)**	**0**	**1**
General Counsel	**29**	**31**	**2**	**0**	**0**	**1**	**0**	**1**
Human Resources	**6**	**7**	**1**	**0**	**(0)**	**0**	**(0)**	**0**
Information Technology	**52**	**56**	**4**	**3**	**(1)**	**1**	**0**	**0**
Corporate	**92**	**105**	**13**	**13**	**0**	**0**	**(0)**	**0**
Enterprise Security	**3**	**3**	**(0)**	**(0)**	**0**	**0**	**0**	**0**
Utility Total	**686**	**731**	**44**	**23**	**9**	**3**	**10**	**0**
Nonutility Total	**29**	**18**	**(11)**	**(5)**	**(0)**	**(1)**	**(0)**	**(4)**
O&M Total YTD	**715**	**749**	**34**	**18**	**9**	**1**	**10**	**(4)**

Case Nos. 2018-00294 and 2018-00295
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Note: Schedules may not sum due to rounding.

Financing Activities — September 2017

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB						
Beg Bal	$ 898.8	$ 898.8	$ 0.0	$ 898.8	$ 898.8	$ 0.0
End Bal	900.1	898.7	(1.4)	890.0	898.7	8.7
Ave Bal	**$ 899.4**	**$ 898.7**	**$ (0.7)**	**$ 894.4**	**$ 898.7**	**$ 4.3**
Interest Exp	**$ 11.7**	**$ 9.0**	**$ (2.7)**	**$ 15.2**	**$ 11.9**	**$ (3.3)**
Rate	**1.72%**	**1.32%**	**-0.40%**	**1.68%**	**1.31%**	**-0.37%**
FMB/Sr Nts/Loan with PPL						
Beg Bal	$ 4,210.0	$ 4,210.0	$ 0.0	$ 4,210.0	$ 4,210.0	$ 0.0
End Bal	4,210.0	4,495.0	285.0	4,384.7	4,608.5	223.8
Ave Bal	**$ 4,210.0**	**$ 4,352.5**	**$ 142.50**	**$ 4,297.3**	**$ 4,409.2**	**$ 111.89**
Interest Exp	**$ 137.4**	**$ 139.3**	**$ 1.9**	**$ 183.1**	**$ 187.7**	**$ 4.6**
Rate	**4.30%**	**4.22%**	**-0.08%**	**4.20%**	**4.20%**	**0.00%**
Short-term Debt						
Beg Bal	$ 348.1	$ 509.7	$ 161.6	$ 348.1	$ 509.7	$ 161.6
End Bal	349.2	378.6	29.4	466.4	530.2	63.8
Ave Bal (1)	**$ 348.6**	**$ 444.1**	**$ 95.5**	**$ 407.2**	**$ 520.0**	**$ 112.7**
Interest Exp	**$ 4.2**	**$ 5.0**	**$ 0.8**	**$ 6.9**	**$ 6.9**	**$ 0.0**
Rate	**1.79%**	**1.49%**	**-0.30%**	**1.67%**	**1.31%**	**-0.36%**
Unamortized Debt Expense Bonds						
Beg Bal	$ (44.0)	$ (43.2)	$ 0.7	$ (44.0)	$ (43.2)	$ 0.75
End Bal	(42.6)	(42.8)	(0.3)	(41.3)	(42.0)	(0.7)
Ave Bal	**$ (43.3)**	**$ (43.0)**	**$ 0.2**	**$ (42.6)**	**$ (42.6)**	**$ 0.0**
Total End Bal	**$ 5,416.7**	**$ 5,729.4**	**$ 312.7**	**$ 5,699.8**	**$ 5,995.3**	**$ 295.6**
Total Average Bal	**$ 5,377.8**	**$ 5,652.4**	**$ 274.6**	**$ 5,556.3**	**$ 5,785.3**	**$ 229.0**
Total Expense Excl I/C (2)	**$ 161.0**	**$ 161.3**	**$ 0.2**	**$ 215.3**	**$ 217.2**	**$ 2.0**
Rate	**3.92%**	**3.73%**	**-0.18%**	**3.79%**	**3.68%**	**-0.12%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use the average of the beginning and ending balances.
(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(3)	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 159		$ 141
LG&E	500	190		310
KU	598	(0)	$ 198	400
TOTAL	$ 1,398	$ 349	$ 198	$ 851

(3) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2017 Actual YTD	LKE 2017 Budget YTD	LG&E 2017 Actual YTD	LG&E 2017 Budget YTD	KU 2017 Actual YTD	KU 2017 Budget YTD
CFO pre-WC / Debt	19%	17%	27%	25%	26%	27%
CFO pre-WC + Interest / Interest	6.1	5.7	7.9	7.9	7.3	7.8
CFO pre-WC - Dividends / Debt	13%	12%	19%	20%	17%	17%
Debt to Capitalization	47%	48%	35%	36%	34%	35%

Credit Metrics Moody's	LKE 2017 BP 2018	LKE 2017 BP 2019	LG&E 2017 BP 2018	LG&E 2017 BP 2019	KU 2017 BP 2018	KU 2017 BP 2019
CFO pre-WC / Debt	18%	18%	27%	29%	26%	26%
CFO pre-WC + Interest / Interest	6.0	5.7	8.6	8.8	7.9	7.6
CFO pre-WC - Dividends / Debt	11%	15%	25%	22%	20%	17%
Debt to Capitalization	50%	49%	35%	34%	34%	34%

[1] Actuals represent a trailing 12 months.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2016	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.
Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.
Moody’s appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — September 2017

($ Millions)

	9/30/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 40	$ 60	$ (20)	Primarily due to a decrease in cash at the non-utility companies partially offset by an increase of cash at the Utilities.
Accounts Receivable (Trade)	369	396	(27)	
Inventory	264	252	12	
Regulatory Assets Current	20	22	(2)	
Prepayments and other current assets	75	38	37	Primarily due to higher accounts receivable related to refined coal, higher other accounts receivable, and higher notes receivable from affiliates; which are partially offset by accounts receivable from affiliates.
Total Current Assets	769	768	1	
Property, Plant, and Equipment	11,794	11,982	(188)	
Intangible Assets	88	90	(2)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	796	923	(127)	Primarily due to pension funded status adjustments, decrease in ARO balances and market adjustments for interest rate swaps.
Goodwill	997	997	0	
Other Long-term Assets	70	80	(11)	Primarily due to lower collateral on interest rate swaps, lower primary survey and investigation charges, lower life insurance and other deferred debits, partially offset by higher Cane Run 7 LTPC assets.
Total Assets	**$ 14,515**	**$ 14,842**	**$ (327)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 291	$ 222	$ 69	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	57	55	3	
Derivative Liability	5	6	(1)	
Accrued Taxes	52	44	8	
Regulatory Liabilities Current	15	19	(4)	
Other Current Liabilities	293	238	55	Primarily due to ARO reclassification from long term to current in actuals versus the budget which assumed a static balance as of September 2017 when the budget was finalized.
Total Current Liabilities	713	584	129	
Debt - Affiliated Company	559	695	(136)	Used tax settlements and dividends from utilities to pay down CEP reserves.
Debt [(1)]	4,857	5,034	(177)	
Total Debt	5,417	5,729	(313)	
Deferred Tax Liabilities	1,909	1,874	35	
Investment Tax Credit	130	129	1	
Accum Provision for Pension & Related Benefits	345	410	(66)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	261	357	(96)	Primarily due to ARO settlements, lower revaluations, and reclassifications from long term to current.
Regulatory Liabilities Non Current	873	852	21	
Derivative Liability	24	28	(4)	
Other Liabilities	178	186	(8)	
Total Deferred Credits and Other Liabilities	3,720	3,837	(117)	
Equity	4,666	4,691	(25)	
Total Liabilities and Equity	**$ 14,515**	**$ 14,842**	**$ (327)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E — September 2017

($ Millions)

	9/30/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 9	$ 5	$ 4	
Accounts Receivable (Trade)	161	168	(7)	
Inventory	137	123	14	Lower fuel burn due to unfavorable weather has resulted in higher than budgeted coal inventory levels.
Regulatory Assets Current	11	6	6	
Prepayments and other current assets	50	47	3	
Total Current Assets	368	349	19	
Property, Plant, and Equipment	5,152	5,232	(80)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	413	493	(80)	Primarily due to a pension funded status adjustment, decrease in ARO balance due to settlements and revaluation and market adjustments for interest rate swaps.
Goodwill	0	0	0	
Other Long-term Assets	12	21	(8)	
Total Assets	**$ 5,952**	**$ 6,101**	**$ (149)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 183	$ 155	$ 28	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	27	26	1	
Derivative Liability	5	6	(1)	
Accrued Taxes	25	28	(3)	
Regulatory Liabilities Current	5	3	3	
Other Current Liabilities	101	99	2	
Total Current Liabilities	346	316	30	
Debt - Affiliated Company	10	0	10	Increase due to notes payable to KU.
Debt [(1)]	1,808	1,898	(90)	
Total Debt	1,817	1,898	(81)	
Deferred Tax Liabilities	1,073	1,066	7	
Investment Tax Credit	36	36	(0)	
Accum Provision for Pension & Related Benefits	47	71	(25)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	85	96	(10)	Decrease primarily due to settlement of Cane Run ash pond and landfill, settlement of Paddy's Run asbestos, reclassification from long term to current, and lower ARO revaluation.
Regulatory Liabilities Non Current	340	342	(2)	
Derivative Liability	24	28	(4)	
Other Liabilities	84	89	(5)	
Total Deferred Credits and Other Liabilities	1,689	1,729	(40)	
Equity	2,099	2,158	(59)	
Total Liabilities and Equity	**$ 5,952**	**$ 6,101**	**$ (149)**	

(1) Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

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Balance Sheet - KU

September 2017

($ Millions)

	9/30/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 31	$ 5	$ 26	Increase primarily due to timing of payments and lower capital expenditures.
Accounts Receivable (Trade)	208	227	(20)	
Inventory	127	129	(2)	
Regulatory Assets Current	9	16	(8)	
Prepayments and other current assets	57	22	35	Primarily due to higher accounts receivable related to refined coal, higher other accounts receivable, and higher notes receivable from LG&E.
Total Current Assets	432	400	32	
Property, Plant, and Equipment	6,634	6,742	(107)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	381	431	(50)	Primarily due to a pension funded status adjustment and decrease in ARO balance due to lower actual accretion and depreciation expense versus budgeted.
Goodwill	0	0	0	
Other Long-term Assets	55	57	(2)	
Total Assets	**$ 7,515**	**$ 7,643**	**$ (128)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 147	$ 110	$ 36	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	30	28	2	
Derivative Liability	0	0	0	
Accrued Taxes	24	24	0	
Regulatory Liabilities Current	10	16	(6)	
Other Current Liabilities	134	86	48	Primarily due to ARO reclassification from long term to current in actuals versus the budget which assumed a static balance as of September 2017 when the budget was finalized.
Total Current Liabilities	344	265	80	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,326	2,413	(87)	
Total Debt	2,326	2,413	(87)	
Deferred Tax Liabilities	1,289	1,321	(33)	
Investment Tax Credit	94	94	1	
Accum Provision for Pension & Related Benefits	37	66	(29)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	176	261	(85)	Primarily due to lower ARO revaluation and reclassification from long term to current.
Regulatory Liabilities Non Current	463	438	25	
Derivative Liability	0	0	0	
Other Liabilities	43	47	(5)	
Total Deferred Credits and Other Liabilities	2,102	2,229	(126)	
Equity	2,742	2,737	5	
Total Liabilities and Equity	**$ 7,515**	**$ 7,643**	**$ (128)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

KU and LG&E Combined
Reconciliation of Allowed Return to
12 months ended September 2017 Regulatory Return
and ROE from Ongoing Operations

Allowed Return (1)		9.96%	
Adjustments (net tax):			
Change in capitalization - non mechanism	-0.20%		Growth in capitalization (rate base) between rate cases does not earn a return
Change in ROE from average mechanism rate base growth	0.00%		Mechanisms have a real-time return
Change in weighted cost of debt	-0.07%		Higher interest rates and borrowing
Change in margins	-0.65%		Lower revenue
Change in allowed expenses	0.56%		Lower expense
		-0.35%	
Actual Regulated ROE		9.61%	

(1) Based on the most recent base rate filings with test years ending 6/30/18 KPSC, 12/31/16 FERC, 12/31/14 VA.
Note the allowed return is a blended rate of the previous authorized ROE of 10% after 7/1/16 and the current authorized ROE of 9.7% after 7/1/17

Performance Report

October 2017

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Kentucky Regulated Dashboard — October 2017

	Current Month		YTD		Full Year	
Safety	Actual	PY	Actual	PY	Forecast	PY
TCIR - Employees(1)	0.37	0.74	0.98	1.09	1.35	1.12
Employee lost-time incidents	0	0	8	3	10	5
Reliability	Actual	Budget	Actual	Budget	Forecast	Budget
Generation Volumes	2,517	2,490	27,268	28,751	32,942	34,425
Utility EFOR	0.8%	5.0%	3.3%	5.0%	N/A	5.0%
Utility EAF	71.3%	69.9%	85.7%	85.8%	N/A	85.2%
Steam Fleet Commercial Availability	92.3%	93.0%	95.1%	93.0%	N/A	93.0%
Combined SAIFI	0.08	0.08	0.74	0.91	N/A	1.03
Combined SAIDI (minutes)	5.30	6.71	65.53	82.68	N/A	93.20
GwH Sales	Actual	Budget	Actual	Budget	Forecast	Budget
Residential	634	635	8,182	8,856	9,972	10,668
Commercial	649	625	6,570	6,619	7,821	7,882
Industrial	757	795	7,715	8,086	9,261	9,706
Municipals	134	134	1,467	1,564	1,761	1,846
Other	233	219	2,293	2,296	2,759	2,753
Off-System Sales	36	7	290	204	330	244
Total	2,443	2,415	26,517	27,624	31,905	33,098
Weather-Normalized Sales Growth			TTM			
Residential			0.43%			
Commercial			-0.37%			
Industrial			-1.21%			
Municipal			-2.96%			
Other			-3.32%			
Total			-0.77%			

	Current Month		YTD		Full Year	
Margins ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Electric Margins(2)	$143	$150	$1,537	$1,616	$1,850	$1,948
Gas Margins	$12	$12	$137	$140	$179	$183
Capital Expenditures ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Total(2)	$116	$138	$750	$899	$1,050	$1,107
O&M ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
O&M – Management View(2) (3)	$64	$72	$579	$624	$706	$749
O&M – GAAP View(2) (4)	$73	$82	$671	$720	$815	$864
Head Count	Actual	Budget	Actual	Budget	Forecast	Budget
Full-time Employees	3,460	3,607	3,460	3,607	3,529	3,591
Other Metrics	Actual	PY	Actual	PY	Forecast	PY
Environmental Events	0	0	5	3	N/A	3
NERC Possible Violations(5)	0	0	7	5	N/A	5

	TTM	Full Year	
Financial Metrics	Actual	Forecast	Budget
Utility ROE(6)	9.5%	9.6%	9.8%
Average Utility Capitalization ($ millions)	$8,938	$8,987	$9,174

Variance Explanations

Lower MTD margins primarily due to lower net retail electric base energy and demand revenue.

Lower YTD margins primarily due to lower sales volumes from unfavorable weather, resulting in lower retail electric base energy and demand revenue of $53 million, lower ECR revenue of $9 million and lower gas margins of $3 million and other offsetting margin components.

Lower O&M MTD primarily due to lower labor and burdens of $4 million and lower outside service expense of $2 million.

Lower O&M YTD primarily due to lower labor and burdens of $14 million, lower outside service expense of $10 million, lower storm and vegetation management expenses of $7 million, lower plant maintenance of $4 million and lower materials of $5 million.

(1) Full year forecast amount shown represents target.

(2) Includes net impact of approved rate case outcome for deferred AMS Capital and O&M expenses, lower depreciation expense and the offsetting revenue reduction included in margins.

(3) Net of cost recovery mechanisms and variable costs of production.

(4) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses

(5) The possible violation issues for YTD Actual is believed to be minimal risk.

(6) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Major Developments

KU announced its intention to retire Brown units 1 and 2 on or about March 1, 2019, coming out of the 2018-2019 winter season and approaching the termination of existing municipal contracts at the end of April 2019. Environmental compliance costs under the coal combustion residuals regulation and plans for the landfill at the site, drove the analysis that led to this conclusion. The retirement of this 272MW of coal-fired generation capacity with a projected future average capacity factor of approximately 20% was the most economic decision for our customers and is consistent with the assumptions in the current version of our 2018 business plan. No replacement capacity is needed given projected reserve margins following the municipal contract termination.

The contract between LG&E and the IBEW was ratified and covers the period from November 11, 2017 through November 10, 2020. The agreement provides for annual wage increases of 3%, 2.5% and 2.5%, among other provisions that give the Company added flexibility.

LKE recently concluded its annual Power of One employee fundraising campaign which benefits United Way agencies across the state as well as Fund for the Arts and Crusade for Children. For the first time in the 13-year history of the campaign, total funds raised exceeded $2 million. The 100th anniversary campaign of Metro United Way and a 68% payroll participation rate drove this memorable result.

LKE has filed responses to the second and third round of data requests regarding the Virginia rate case.

LG&E recently entered into a $200 million two year term loan credit facility with US Bank and made the first of two $100 million draws. The second draw is expected to occur in early 2018. This loan has a variable rate of Libor plus 50 basis points and will be reset every 30 days, with an initial rate of 1.74 percent. The proceeds will be used to pay down LG&E commercial paper balances, providing cost-effective liquidity prior to LG&E's next first mortgage bond issuance.

Significant Future Events

The Virginia State Corporation Commission will conduct on site audits regarding the Virginia rate case for two separate weeks in November. These visits are consistent with past practice.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — October 2017

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 220	$ 232	$ (12)	Due primarily to lower retail electric base energy and demand revenue.
Gas Revenues	18	16	2	
Total Revenues	238	248	(10)	
Cost of Sales:				
Fuel Electric Costs	58	58	(0)	
Gas Supply Expenses	6	4	(2)	
Purchased Power	5	5	(0)	
Other Electric Cost of Production	3	3	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	6	6	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	9	4	
Total Cost of Sales	83	86	2	
Gross Margin:				
Electric Margin	143	150	(7)	See explanations above.
Gas Margin	12	12	0	
Total Gross Margin	155	162	(7)	
O&M	64	72	8	Primarily due to lower labor and burdens and lower outside service expense.
Depreciation & Amortization	33	36	3	
Taxes, Other than Income	5	5	(0)	
Other income (expense)	(0)	(0)	0	
EBIT	52	48	4	
Interest Expense	18	19	1	
Income from Ongoing Operations before income taxes	34	30	5	
Income Tax Expense	13	11	(2)	
Net Income (loss) from ongoing operations	**21**	**18**	**3**	
Special Item - EEI	0	0	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 21	$ 18	$ 2	
KY Regulated Financing Costs	(3)	$ (3)	(0)	
KY Regulated Net Income	$ 18	$ 16	$ 2	
Earnings Per Share - Ongoing	$ 0.03	$ 0.02	$ 0.00	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — October 2017

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 2,361	$ 2,505	$ (144)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	229	255	(25)	Due primarily to lower sales volumes driven by unfavorable weather in Q1.
Total Revenues	2,590	2,760	(169)	
Cost of Sales:				
Fuel Electric Costs	637	679	42	Primarily due to decreased generation as a result of unfavorable weather.
Gas Supply Expenses	83	105	21	Due primarily to lower gas usage as a result of unfavorable weather.
Purchased Power	48	50	2	
Other Electric Cost of Production	30	35	5	Primarily due to decreased generation as a result of unfavorable weather and a reclassification of resale expense to revenues in actuals.
Mechanism - ECR, DSM & GLT - Operation and Maintenance	61	62	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	57	74	16	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates which is offset in margins.
Total Cost of Sales	916	1004	88	
Gross Margin:				
Electric Margin	1,537	1,616	(79)	See explanations above.
Gas Margin	137	140	(3)	
Total Gross Margin	1,675	1,756	(82)	
O&M	579	624	45	Primarily due to lower labor and burdens, lower outside service expense, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	309	323	14	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Taxes, Other than Income	50	51	1	
Other income (expense)	(6)	(6)	0	
EBIT	731	753	(22)	
Interest Expense	179	180	1	
Income from Ongoing Operations before income taxes	552	573	(21)	
Income Tax Expense	209	218	10	
Net Income (loss) from ongoing operations	**343**	**355**	**(12)**	
Special Item - EEI	(1)	0	(1)	
Discontinued Operations	1	0	0	
Net Income (loss)	$ 343	$ 355	$ (12)	
KY Regulated Financing Costs	(25)	(25)	(0)	
KY Regulated Net Income	318	$ 330	$ (12)	
Earnings Per Share - Ongoing	$ 0.46	$ 0.48	$ (0.01)	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LG&E — October 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 959	$ 1,004	$ (45)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	229	255	(25)	Due primarily to lower sales volumes driven by unfavorable weather in Q1.
Total Revenues	1,188	1259	(71)	
Cost of Sales:				
Fuel Electric Costs	253	255	2	
Gas Supply Expenses	83	105	21	Due primarily to lower gas usage as a result of unfavorable weather.
Purchased Power	41	48	7	Lower intercompany and market purchases driven by unfavorable weather.
Other Electric Cost of Production	11	13	2	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	23	25	2	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	30	37	8	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates which is offset in margins.
Total Cost of Sales	441	482	42	
Gross Margin:				
Electric Margin	610	636	(26)	See explanations above.
Gas Margin	137	140	(3)	
Total Gross Margin	747	776	(29)	
O&M	257	280	23	Primarily due to lower outside service expense, lower labor and burdens, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	125	131	6	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Taxes, Other than Income	25	26	1	
Other income (expense)	(3)	(3)	(0)	
EBIT	338	336	1	
Interest Expense	58	59	1	
Income from Ongoing Operations before income taxes	280	278	2	
Income Tax Expense	106	106	(0)	
Net Income (loss) from ongoing operations	**$ 173**	**$ 171**	**$ 2**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Actual vs. Budget (YTD) - KU — October 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,436	$ 1,545	$ (110)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	0	0	0	
Total Revenues	1,436	1,545	(110)	
Cost of Sales:				
Fuel Electric Costs	388	427	39	Primarily due to decreased generation as a result of unfavorable weather.
Gas Supply Expenses	0	0	0	
Purchased Power	37	43	6	Lower intercompany and market purchases driven by unfavorable weather.
Other Electric Cost of Production	18	22	4	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	38	37	(1)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	28	36	9	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Total Cost of Sales	508	565	57	
Gross Margin:				
Electric Margin	927	980	(53)	See explanations above.
Gas Margin	0	0	0	
Total Gross Margin	927	980	(53)	
O&M	297	328	30	Primarily due to lower outside service expense, lower labor and burdens, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	184	191	7	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Taxes, Other than Income	25	25	0	
Other income (expense)	(2)	(3)	1	
EBIT	419	433	(14)	
Interest Expense	80	80	(1)	
Income from Ongoing Operations before income taxes	339	353	(14)	
Income Tax Expense	129	134	5	
Net Income (loss) from ongoing operations	**$ 210**	**$ 219**	**$ (9)**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

O&M	October 2017

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	23	27	3	1	(0)	1	1	0
Project Engineering	0	0	0	0	(0)	0	0	0
Transmission	3	3	0	0	0	(0)	0	0
Energy Supply and Analysis	1	1	0	0	0	0	0	0
Electric Distribution	5	6	1	0	1	(0)	0	0
Gas Distribution	3	3	0	0	(0)	0	(0)	0
Advanced Metering System	0	1	1	0	0	0	0	(0)
Safety and Technical Training	0	0	0	0	(0)	(0)	(0)	0
Customer Services	8	9	1	0	0	0	(0)	0
SVP Operations Total	**44**	**50**	**6**	**2**	**1**	**1**	**1**	**1**
Audit Services	0	0	0	0	0	0	0	0
Controller	1	1	(0)	0	0	(0)	0	(0)
Supply Chain	0	0	0	0	0	(0)	0	(0)
Treasurer	2	2	0	0	0	0	0	0
State Regulation and Rates	0	0	(0)	0	0	(0)	(0)	0
Other	0	0	0	0	0	(0)	0	0
Chief Financial Officer Total	**4**	**4**	**0**	**0**	**0**	**(0)**	**(0)**	**0**
General Counsel	**2**	**2**	**(0)**	**(0)**	**0**	**(0)**	**0**	**0**
Human Resources	**1**	**1**	**0**	**(0)**	**0**	**(0)**	**0**	**0**
Information Technology	**4**	**5**	**1**	**0**	**(0)**	**0**	**0**	**0**
Corporate	**7**	**9**	**2**	**2**	**0**	**0**	**(0)**	**(0)**
Communication	**1**	**1**	**0**	**(0)**	**0**	**0**	**(0)**	**0**
Enterprise Security	**0**	**0**	**0**	**0**	**0**	**(0)**	**(0)**	**0**
Utility Total	**63**	**71**	**8**	**4**	**1**	**1**	**1**	**1**
Nonutility	**2**	**2**	**0**	**0**	**0**	**0**	**0**	**(0)**
O&M Total MTD	**64**	**72**	**8**	**4**	**1**	**1**	**1**	**1**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Resident Contractors	Other Outside Services	Materials	Other
Generation	162	179	17	4	(1)	6	10	(3)
Project Engineering	6	0	(5)	(0)	(0)	(4)	(0)	(1)
Transmission	26	29	3	0	1	2	(0)	0
Energy Supply and Analysis	10	11	0	0	0	(0)	0	0
Electric Distribution	55	63	8	0	10	(3)	1	1
Gas Distribution	29	29	0	1	(0)	0	0	(0)
Advanced Metering System	0	2	2	1	0	1	0	(0)
Safety and Technical Training	4	4	0	(0)	(0)	(0)	(0)	0
Customer Services	77	83	6	1	2	1	0	2
SVP Operations Total	**369**	**401**	**33**	**7**	**12**	**4**	**11**	**0**
Audit Services	1	1	0	0	0	0	0	0
Controller	7	7	0	(0)	(0)	0	0	0
Supply Chain	3	4	0	0	(0)	(0)	0	0
Treasurer	20	20	1	(0)	0	(0)	0	1
State Regulation and Rates	3	3	0	(0)	0	0	0	0
Other	2	2	0	0	0	(0)	0	(0)
Chief Financial Officer Total	**37**	**38**	**2**	**0**	**(0)**	**(0)**	**0**	**1**
General Counsel	**16**	**20**	**4**	**0**	**0**	**2**	**0**	**1**
Human Resources	**5**	**6**	**1**	**0**	**(0)**	**0**	**0**	**0**
Information Technology	**43**	**47**	**4**	**2**	**(0)**	**2**	**0**	**1**
Corporate	**78**	**87**	**10**	**9**	**0**	**0**	**(0)**	**(0)**
Communication	**5**	**6**	**1**	**0**	**0**	**0**	**0**	**0**
Enterprise Security	**2**	**2**	**0**	**(0)**	**0**	**0**	**0**	**0**
Utility Total	**554**	**608**	**54**	**19**	**11**	**8**	**11**	**4**
Nonutility	**24**	**15**	**(9)**	**(4)**	**0**	**(1)**	**(0)**	**(3)**
O&M Total YTD	**579**	**624**	**45**	**15**	**11**	**7**	**11**	**1**

Note: Schedules may not sum due to rounding.

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Financing Activities — October 2017

($ Millions)

Balance Sheet	YTD Actual		YTD Budget		Variance	
PCB						
Beg Bal	$	898.8	$	898.8	$	0.0
End Bal		900.1		898.7		(1.4)
Ave Bal	**$**	**899.4**	**$**	**898.7**	**$**	**(0.7)**
Interest Exp	**$**	**12.9**	**$**	**10.0**	**$**	**(2.9)**
Rate		**1.69%**		**1.31%**		**-0.38%**
FMB/Sr Nts/Loan with PPL						
Beg Bal	$	4,210.0	$	4,210.0	$	0.0
End Bal		4,310.0		4,495.0		185.0
Ave Bal	**$**	**4,260.0**	**$**	**4,352.5**	**$**	**92.50**
Interest Exp	**$**	**152.7**	**$**	**155.3**	**$**	**2.6**
Rate		**4.25%**		**4.23%**		**-0.02%**
Short-term Debt						
Beg Bal	$	348.1	$	509.7	$	161.6
End Bal		232.8		454.5		221.7
Ave Bal (1)	**$**	**290.4**	**$**	**482.1**	**$**	**191.7**
Interest Exp	**$**	**4.8**	**$**	**5.6**	**$**	**0.8**
Rate		**1.82%**		**1.37%**		**-0.45%**
Unamortized Debt Expense Bonds						
Beg Bal	$	(44.0)	$	(43.2)	$	0.7
End Bal		(42.3)		(43.0)		(0.7)
Ave Bal	**$**	**(43.1)**	**$**	**(43.1)**	**$**	**0.0**
Total End Bal	**$**	**5,400.6**	**$**	**5,805.1**	**$**	**404.6**
Total Average Bal	**$**	**5,428.3**	**$**	**5,690.2**	**$**	**261.9**
Total Expense Excl I/C (2)	**$**	**178.9**	**$**	**179.8**	**$**	**0.9**
Rate		**3.87%**		**3.71%**		**-0.16%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use the average of the beginning and ending balances.
(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity		Borrowed(3)		Letters of Credit Issued		Unused Capacity		Money Pool Loans	
LKE	$	300	$	178			$	122		
LG&E		500		55				445	$	57
KU		598		(0)	$	198		400		
TOTAL	$	1,398	$	233	$	198	$	967	$	57

(3) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2017 Actual YTD	LKE 2017 Budget YTD	LG&E 2017 Actual YTD	LG&E 2017 Budget YTD	KU 2017 Actual YTD	KU 2017 Budget YTD
CFO pre-WC / Debt	19%	17%	27%	25%	26%	27%
CFO pre-WC + Interest / Interest	5.8	5.7	7.9	7.9	7.2	7.9
CFO pre-WC - Dividends / Debt	12%	12%	18%	20%	16%	17%
Debt to Capitalization	46%	48%	35%	36%	34%	35%

Credit Metrics Moody's	LKE 2017 BP 2018	LKE 2017 BP 2019	LG&E 2017 BP 2018	LG&E 2017 BP 2019	KU 2017 BP 2018	KU 2017 BP 2019
CFO pre-WC / Debt	18%	18%	27%	29%	26%	26%
CFO pre-WC + Interest / Interest	6.0	5.7	8.6	8.8	7.9	7.6
CFO pre-WC - Dividends / Debt	11%	15%	25%	22%	20%	17%
Debt to Capitalization	50%	49%	35%	34%	34%	34%

(1) Actuals represent a trailing 12 months.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2016	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — October 2017

($ Millions)

	10/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 13	$ 60	$ (47)	Primarily due to a decrease in cash at the non-utility companies.
Accounts Receivable (Trade)	358	372	(14)	
Inventory	266	260	6	
Regulatory Assets Current	22	25	(3)	
Prepayments and other current assets	74	36	38	Primarily due to higher accounts receivable related to refined coal, higher other accounts receivable, higher prepayments, higher preliminary survey charges and higher clearing accounts; which are offset partially by lower provision for accounts receivable bad debt.
Total Current Assets	734	754	(20)	
Property, Plant, and Equipment	11,867	12,066	(199)	
Intangible Assets	88	90	(2)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	797	925	(128)	Primarily due to pension funded status adjustments, decrease in ARO balances and market adjustments for interest rate swaps.
Goodwill	997	997	0	
Other Long-term Assets	60	80	(20)	Primarily due to lower collateral on interest rate swaps, lower primary survey and investigation charges, lower life insurance and other deferred debits and lower Cane Run 7 LTPC assets.
Total Assets	**$ 14,544**	**$ 14,912**	**$ (369)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 322	$ 216	$ 107	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	57	55	3	
Derivative Liability	4	6	(2)	
Accrued Taxes	70	37	33	Primarily due to timing of property tax payments expected to occur during the month in the budget.
Regulatory Liabilities Current	11	19	(8)	
Other Current Liabilities	273	230	42	Primarily due to ARO reclassification from long term to current in actuals versus the budget which assumed a static balance as of September 2016 when the budget was finalized.
Total Current Liabilities	737	563	174	
Debt - Affiliated Company	578	705	(128)	Used tax settlements and dividends from utilities to pay down CEP reserves.
Debt [(1)]	4,823	5,100	(277)	
Total Debt	5,401	5,805	(405)	
Deferred Tax Liabilities	1,909	1,874	35	
Investment Tax Credit	130	129	1	
Accum Provision for Pension & Related Benefits	347	410	(63)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	260	355	(95)	Primarily due to ARO settlements, lower revaluations and reclassifications from long term to current.
Regulatory Liabilities Non Current	872	851	21	
Derivative Liability	23	28	(5)	
Other Liabilities	178	186	(8)	
Total Deferred Credits and Other Liabilities	3,719	3,833	(114)	
Equity	4,687	4,711	(24)	
Total Liabilities and Equity	**$ 14,544**	**$ 14,912**	**$ (369)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

October 2017

($ Millions)

	10/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 4	$ 5	$ (1)	
Accounts Receivable (Trade)	156	156	(1)	
Inventory	142	132	10	
Regulatory Assets Current	13	7	5	
Prepayments and other current assets	49	46	3	
Total Current Assets	364	347	17	
Property, Plant, and Equipment	5,191	5,280	(89)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	413	492	(79)	Primarily due to a pension funded status adjustment, decrease in ARO balance due to settlements and revaluation and market adjustments for interest rate swaps.
Goodwill	0	0	0	
Other Long-term Assets	10	21	(11)	Primarily due to lower collateral on interest rate swaps, lower primary survey and investigation charges and lower prepaid LT insurance.
Total Assets	**$ 5,984**	**$ 6,146**	**$ (162)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 196	$ 154	$ 43	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	27	26	1	
Derivative Liability	4	6	(2)	
Accrued Taxes	35	27	8	
Regulatory Liabilities Current	4	3	1	
Other Current Liabilities	87	94	(7)	
Total Current Liabilities	354	310	44	
Debt - Affiliated Company	57	0	57	Increase due to notes payable to KU.
Debt [(1)]	1,773	1,943	(170)	
Total Debt	1,830	1,943	(113)	
Deferred Tax Liabilities	1,073	1,066	7	
Investment Tax Credit	35	35	(0)	
Accum Provision for Pension & Related Benefits	47	70	(23)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	85	95	(10)	Decrease primarily due to settlement of Cane Run ash pond and landfill, settlement of Paddy's Run asbestos, reclassification from long term to current and lower ARO revaluation.
Regulatory Liabilities Non Current	341	341	(0)	
Derivative Liability	23	28	(5)	
Other Liabilities	86	90	(4)	
Total Deferred Credits and Other Liabilities	1,690	1,725	(35)	
Equity	2,110	2,168	(58)	
Total Liabilities and Equity	**$ 5,984**	**$ 6,146**	**$ (162)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

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Balance Sheet - KU

October 2017

($ Millions)

	10/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 9	$ 5	$ 4	
Accounts Receivable (Trade)	202	216	(13)	
Inventory	124	128	(4)	
Regulatory Assets Current	10	18	(8)	
Prepayments and other current assets	102	21	81	Primarily due to higher accounts receivable related to refined coal, higher other accounts receivable, higher prepayments, higher notes receivable from LG&E, higher preliminary survey charges and higher clearing accounts; which are partially offset by lower accounts receivable from associated companies.
Total Current Assets	447	387	60	
Property, Plant, and Equipment	6,668	6,778	(110)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	382	434	(52)	Primarily due to a pension funded status adjustment and decrease in ARO balance due to lower actual accretion and depreciation expense versus budgeted.
Goodwill	0	0	0	
Other Long-term Assets	48	57	(9)	
Total Assets	**$ 7,558**	**$ 7,670**	**$ (112)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 175	$ 109	$ 65	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	30	28	1	
Derivative Liability	0	0	0	
Accrued Taxes	35	20	15	Primarily due to timing of property tax payments expected to occur during the month in the budget.
Regulatory Liabilities Current	7	16	(9)	
Other Current Liabilities	130	84	46	Primarily due to ARO reclassification from long term to current in actuals versus the budget which assumed a static balance as of September 2016 when the budget was finalized.
Total Current Liabilities	376	258	118	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,326	2,434	(108)	
Total Debt	2,326	2,434	(108)	
Deferred Tax Liabilities	1,289	1,322	(33)	
Investment Tax Credit	94	94	1	
Accum Provision for Pension & Related Benefits	38	66	(28)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	175	260	(85)	Primarily due to lower ARO revaluation and reclassification from long term to current.
Regulatory Liabilities Non Current	462	439	23	
Derivative Liability	0	0	0	
Other Liabilities	42	48	(6)	
Total Deferred Credits and Other Liabilities	2,100	2,228	(129)	
Equity	2,756	2,749	7	
Total Liabilities and Equity	**$ 7,558**	**$ 7,670**	**$ (112)**	

(1) Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

Performance Report

November 2017

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Kentucky Regulated Dashboard — November 2017

	Current Month		YTD		Full Year	
Safety	Actual	PY	Actual	PY	Forecast	PY
TCIR - Employees[1]	0.72	1.45	0.96	1.12	1.35	1.12
Employee lost-time incidents	0	1	8	4	9	5
Reliability	Actual	Budget	Actual	Budget	Forecast	Budget
Generation Volumes	2,472	2,614	29,740	31,365	32,800	34,425
Utility EFOR	4.9%	5.0%	3.4%	5.0%	N/A	5.0%
Utility EAF	66.8%	71.8%	84.0%	84.6%	N/A	85.2%
Steam Fleet Commercial Availability	80.3%	93.0%	93.8%	93.0%	N/A	93.0%
Combined SAIFI	0.05	0.06	0.79	0.97	N/A	1.03
Combined SAIDI (minutes)	5.98	4.96	71.51	87.64	N/A	93.20
GwH Sales	Actual	Budget	Actual	Budget	Forecast	Budget
Residential	752	756	8,933	9,612	9,976	10,668
Commercial	597	606	7,167	7,225	7,815	7,882
Industrial	737	811	8,452	8,896	9,218	9,706
Municipals	132	134	1,600	1,698	1,757	1,846
Other	213	223	2,506	2,519	2,743	2,753
Off-System Sales	8	7	298	211	331	244
Total	2,439	2,537	28,956	30,161	31,841	33,098
Weather-Normalized Sales Growth			TTM			
Residential			1.91%			
Commercial			-0.18%			
Industrial			-3.16%			
Municipal			-2.98%			
Other			-3.20%			
Total			-0.80%			

	Current Month		YTD		Full Year	
Margins ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Electric Margins[2]	$147	$155	$1,685	$1,772	$1,850	$1,948
Gas Margins	$19	$17	$156	$158	$179	$183
Capital Expenditures ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Total[2]	$113	$106	$863	$1,005	$1,020	$1,107
O&M ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
O&M – Management View[2] [3]	$59	$67	$638	$690	$706	$749
O&M – GAAP View[2] [4]	$69	$76	$740	$795	$815	$864
Head Count	Actual	Budget	Actual	Budget	Forecast	Budget
Full-time Employees	3,459	3,598	3,459	3,598	3,509	3,591
Other Metrics	Actual	PY	Actual	PY	Forecast	PY
Environmental Events	2	0	7	3	N/A	3
NERC Possible Violations[5]	1	0	8	5	N/A	5

	TTM	Full Year	
Financial Metrics	Actual	Forecast	Budget
Utility ROE[6]	9.7%	9.6%	9.8%
Average Utility Capitalization ($ millions)	$8,946	$8,987	$9,174

Variance Explanations

Lower margins MTD primarily due to lower net retail electric base energy and demand revenue and lower ECR revenue partially offset by higher gas margins.

Lower margins YTD primarily due to lower sales volumes from unfavorable weather, resulting in lower retail electric base energy and demand revenue of $55 million, lower ECR revenue of $10 million and other offsetting margin components.

'Lower O&M MTD primarily due to lower labor and burdens of $4 million.

Lower O&M YTD primarily due to lower labor and burdens of $19 million, lower outside service expense of $12 million, lower storm and vegetation management expenses of $6 million, lower plant maintenance of $5 million and lower materials of $5 million.

(1) Full year forecast amount shown represents target.

(2) Includes net impact of approved rate case outcome for deferred AMS Capital and O&M expenses, lower depreciation expense and the offsetting revenue reduction included in margins.

(3) Net of cost recovery mechanisms and variable costs of production.

(4) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses

(5) The possible violation issues for YTD Actual is believed to be minimal risk.

(6) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Major Developments

LKE announced that the Company will request that the KPSC extend some of its current Demand Side Management programs through December 31, 2025. All of the current programs are set to expire December 31, 2018. Some of the existing programs are no longer cost-effective and will not be renewed as a result of a variety of factors including the abundance of more energy-efficient appliances and devices and lighting in homes and businesses. The request allows the Company to continue offering customers, especially some of our most vulnerable ones, energy efficiency choices and it also provides programs which engage the industrial segment for the first time. DSM expenses are generally a direct pass-through to customer bills. If LG&E and KU's new plan is approved, residential customers' bills would be reduced $20 to $30 annually in 2018, and $35 to $45 in 2019.

Ohio Falls Unit 8 was recently declared in service for operation. This marked the last of the eight units to be rehabilitated with the new runner technology from Voith Hydro that increased each unit's generating capacity from 10 MW to 12.6 MW, thus increasing the total capacity of the Ohio Falls Station from 80 MW to 109 MW. The overall project maintained an outstanding safety record with only two minor recordables over the project. The project scope included not only the increase in generating capacity, but the rewinding of seven of the unit's generators, upgrade of the electrical power and control systems, as well as site restoration scopes.

Significant Future Events

In January 2018, the Company plans to file a request for a certificate of public necessity and convenience with the KPSC for full scale deployment of advanced metering systems.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated   November 2017

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 227	$ 240	$ (13)	Due primarily to lower retail electric base energy and demand revenue and lower ECR revenue.
Gas Revenues	33	28	4	
Total Revenues	259	268	(9)	
Cost of Sales:				
Fuel Electric Costs	59	62	3	
Gas Supply Expenses	13	10	(3)	
Purchased Power	6	5	(1)	
Other Cost of Production	3	3	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	7	6	(1)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	9	4	
Total Cost of Sales	93	95	2	
Gross Margin:				
Electric Margin	147	155	(8)	See explanations above.
Gas Margin	19	17	1	
Total Gross Margin	166	173	(7)	
O&M	59	67	8	Primarily due to lower labor and burdens.
Depreciation & Amortization	33	36	3	
Taxes, Other than Income	5	5	(0)	
Other income (expense)	(0)	(1)	0	
EBIT	69	64	4	
Interest Expense	18	19	1	
Income from Ongoing Operations before income taxes	51	45	5	
Income Tax Expense	19	17	(2)	
Net Income (loss) from ongoing operations	**31**	**28**	**3**	
Special Item - EEI	0	0	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 31	$ 28	$ 3	
KY Regulated Financing Costs	(3)	$ (2)	(0)	
KY Regulated Net Income	$ 29	$ 26	$ 3	
Earnings Per Share - Ongoing	$ 0.04	$ 0.04	$ 0.00	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LKE Consolidated

November 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,589	$ 2,745	$ (156)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	262	283	(21)	Due primarily to lower sales volumes driven by unfavorable weather in Q1.
Total Revenues	2,850	3,028	(177)	
Cost of Sales:				
Fuel Electric Costs	695	741	46	Primarily due to decreased generation as a result of unfavorable weather.
Gas Supply Expenses	94	115	21	Due primarily to lower gas usage as a result of unfavorable weather.
Purchased Power	56	55	(1)	
Other Cost of Production	34	38	4	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	68	67	(0)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	63	83	20	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates which is offset in margins.
Total Cost of Sales	1,010	1,099	89	
Gross Margin:				
Electric Margin	1,685	1,772	(87)	See explanations above.
Gas Margin	156	158	(1)	
Total Gross Margin	1,841	1,929	(88)	
O&M	638	690	52	Primarily due to lower labor and burdens, lower outside service expense, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	342	359	17	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Taxes, Other than Income	55	56	1	
Other income (expense)	(6)	(7)	1	
EBIT	799	817	(18)	
Interest Expense	197	198	2	
Income from Ongoing Operations before income taxes	603	619	(16)	
Income Tax Expense	228	236	8	
Net Income (loss) from ongoing operations	**374**	**383**	**(8)**	
Special Item - EEI	(1)	0	(1)	
Discontinued Operations	1	0	0	
Net Income (loss)	$ 374	$ 383	$ (9)	
KY Regulated Financing Costs	(28)	(28)	(0)	
KY Regulated Net Income	347	$ 356	$ (9)	
Earnings Per Share - Ongoing	$ 0.50	$ 0.51	$ (0.01)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E — November 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,045	$ 1,095	$ (50)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	262	283	(21)	Due primarily to lower sales volumes driven by unfavorable weather in Q1.
Total Revenues	1,306	1378	(72)	
Cost of Sales:				
Fuel Electric Costs	270	276	5	
Gas Supply Expenses	94	115	21	Due primarily to lower gas usage as a result of unfavorable weather.
Purchased Power	47	52	5	Lower intercompany and market purchases driven by unfavorable weather.
Other Cost of Production	15	14	(1)	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	26	27	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	32	42	10	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates which is offset in margins.
Total Cost of Sales	484	526	41	
Gross Margin:				
Electric Margin	666	695	(29)	See explanations above.
Gas Margin	156	158	(1)	
Total Gross Margin	822	853	(30)	
O&M	284	315	31	Primarily due to lower labor and burdens, lower outside service expense, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	138	146	8	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Taxes, Other than Income	28	29	1	
Other income (expense)	(3)	(3)	(0)	
EBIT	370	360	9	
Interest Expense	64	65	1	
Income from Ongoing Operations before income taxes	306	295	11	
Income Tax Expense	117	113	(3)	
Net Income (loss) from ongoing operations	**$ 189**	**$ 182**	**$ 7**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Actual vs. Budget (YTD) - KU — November 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,580	$ 1,697	$ (118)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	0	0	0	
Total Revenues	1,580	1,697	(118)	
Cost of Sales:				
Fuel Electric Costs	428	468	40	Primarily due to decreased generation as a result of unfavorable weather.
Gas Supply Expenses	0	0	0	
Purchased Power	41	47	5	Lower intercompany and market purchases driven by unfavorable weather.
Other Cost of Production	19	25	6	Primarily due to decreased generation as a result of unfavorable weather.
Mechanism - ECR, DSM & GLT - Operation and Maintenance	41	40	(2)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	31	41	11	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Total Cost of Sales	561	621	60	
Gross Margin:				
Electric Margin	1,019	1076	(58)	See explanations above.
Gas Margin	0	0	0	
Total Gross Margin	1,019	1076	(58)	
O&M	328	358	30	Primarily due to lower labor and burdens, lower outside service expense, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	203	212	9	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Taxes, Other than Income	27	27	0	
Other income (expense)	(2)	(4)	2	
EBIT	457	475	(17)	
Interest Expense	88	88	(1)	
Income from Ongoing Operations before income taxes	369	387	(18)	
Income Tax Expense	140	147	7	
Net Income (loss) from ongoing operations	**$ 229**	**$ 240**	**$ (11)**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

O&M								November 2017
($ Millions)								
	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	20	23	3	1	(0)	1	1	0
Project Engineering	0	0	0	0	(0)	(0)	0	0
Transmission	3	3	(0)	0	(0)	(0)	(0)	0
Energy Supply and Analysis	1	1	0	0	0	(0)	0	0
Electric Distribution	6	6	(0)	0	0	(0)	0	(0)
Gas Distribution	3	3	0	0	0	(0)	0	(0)
Advanced Metering System	0	1	1	0	0	0	0	(0)
Safety and Technical Training	0	0	(0)	0	(0)	0	(0)	(0)
Customer Services	8	8	0	0	0	0	(0)	(0)
SVP Operations Total	**41**	**45**	**4**	**2**	**(0)**	**1**	**1**	**0**
Audit Services	0	0	0	0	0	0	(0)	0
Controller	1	1	0	0	0	0	0	0
Supply Chain	0	0	0	0	0	0	0	(0)
Information Technology	4	5	1	1	(0)	0	(0)	0
Treasurer	2	2	0	0	0	(0)	0	0
State Regulation and Rates	0	0	0	(0)	0	0	(0)	0
Other	0	0	0	0	0	(0)	(0)	0
Chief Financial Officer Total	**8**	**8**	**1**	**1**	**(0)**	**0**	**(0)**	**0**
General Counsel	**1**	**2**	**0**	**0**	**0**	**0**	**0**	**0**
Human Resources	**1**	**1**	**0**	**0**	**(0)**	**0**	**(0)**	**0**
Corporate	**7**	**9**	**2**	**2**	**0**	**(0)**	**(0)**	**0**
Communication	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Utility Total	**58**	**65**	**8**	**4**	**(0)**	**1**	**1**	**1**
Nonutility	**2**	**2**	**(0)**	**0**	**0**	**(0)**	**0**	**(0)**
O&M Total MTD	**59**	**67**	**8**	**4**	**(0)**	**1**	**1**	**1**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	182	202	20	5	(1)	8	11	(3)
Project Engineering	6	1	(5)	(0)	(0)	(4)	(0)	(1)
Transmission	29	31	3	0	1	2	(0)	1
Energy Supply and Analysis	11	12	0	0	0	(0)	0	0
Electric Distribution	60	69	8	1	10	(4)	1	1
Gas Distribution	32	32	1	1	(0)	0	0	(0)
Advanced Metering System	0	3	3	1	0	2	0	(0)
Safety and Technical Training	5	5	0	(0)	(0)	(0)	(0)	0
Customer Services	85	91	6	1	2	1	(0)	2
SVP Operations Total	**410**	**446**	**36**	**8**	**11**	**5**	**12**	**0**
Audit Services	1	2	0	0	0	0	(0)	0
Controller	8	8	0	(0)	(0)	0	0	0
Supply Chain	4	4	0	0	(0)	(0)	0	(0)
Information Technology	47	52	5	2	(0)	2	(0)	1
Treasurer	21	22	1	(0)	0	(0)	0	1
State Regulation and Rates	4	4	0	(0)	0	0	0	0
Other	2	2	0	1	0	(0)	0	0
Chief Financial Officer Total	**87**	**94**	**7**	**3**	**(0)**	**2**	**0**	**2**
General Counsel	**18**	**22**	**4**	**1**	**0**	**2**	**0**	**1**
Human Resources	**6**	**7**	**1**	**0**	**(0)**	**0**	**0**	**0**
Corporate	**87**	**99**	**12**	**11**	**0**	**1**	**(0)**	**1**
Communication	**6**	**6**	**1**	**0**	**0**	**0**	**0**	**0**
Utility Total	**612**	**673**	**61**	**24**	**11**	**10**	**12**	**5**
Nonutility	**26**	**17**	**(9)**	**(4)**	**[illegible]**	**(1)**	**(0)**	**(3)**
O&M Total YTD	**638**	**690**	**52**	**19**	**11**	**[illegible]**	**12**	**2**

Note: Schedules may not sum due to rounding.

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Financing Activities November 2017

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance
PCB			
Beg Bal	$ 898.8	$ 898.8	$ 0.0
End Bal	890.0	898.6	8.7
Ave Bal	**$ 894.4**	**$ 898.7**	**$ 4.3**
Interest Exp	**$ 14.0**	**$ 10.9**	**$ (3.0)**
Rate	**1.69%**	**1.31%**	**-0.37%**
FMB/Sr Nts/Loan with PPL			
Beg Bal	$ 4,210.0	$ 4,210.0	$ 0.0
End Bal	4,310.0	4,495.0	185.0
Ave Bal	**$ 4,260.0**	**$ 4,352.5**	**$ 92.50**
Interest Exp	**$ 168.1**	**$ 171.4**	**$ 3.3**
Rate	**4.25%**	**4.24%**	**-0.01%**
Short-term Debt			
Beg Bal	$ 348.1	$ 509.7	$ 161.6
End Bal	291.0	529.7	238.8
Ave Bal (1)	**$ 319.5**	**$ 519.7**	**$ 200.2**
Interest Exp	**$ 5.3**	**$ 6.2**	**$ 0.9**
Rate	**1.86%**	**1.29%**	**-0.57%**
Unamortized Debt Expense Bonds			
Beg Bal	$ (44.0)	$ (43.2)	$ 0.7
End Bal	(42.0)	(42.5)	(0.6)
Ave Bal	**$ (43.0)**	**$ (42.9)**	**$ 0.1**
Total End Bal	**$ 5,449.0**	**$ 5,880.9**	**$ 431.9**
Total Average Bal	**$ 5,418.9**	**$ 5,728.1**	**$ 309.2**
Total Expense Excl I/C (2)	**$ 196.8**	**$ 198.4**	**$ 1.6**
Rate	**3.88%**	**3.71%**	**-0.18%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use the average of the beginning and ending balances.

(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(3)	Letters of Credit Issued	Unused Capacity	Money Pool Loans
LKE	$ 300	$ 179		$ 121	
LG&E	500	112		388	$ 43
KU	598	-	$ 198	400	
TOTAL	$ 1,398	$ 291	$ 198	$ 909	$ 43

(3) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2017 Actual YTD	LKE 2017 Budget YTD	LG&E 2017 Actual YTD	LG&E 2017 Budget YTD	KU 2017 Actual YTD	KU 2017 Budget YTD
CFO pre-WC / Debt	20%	17%	27%	25%	27%	27%
CFO pre-WC + Interest / Interest	6.0	5.7	8.1	8.0	7.6	8.0
CFO pre-WC - Dividends / Debt	13%	12%	19%	20%	18%	18%
Debt to Capitalization	47%	49%	35%	37%	34%	35%

Credit Metrics Moody's	LKE 2017 BP 2018	LKE 2017 BP 2019	LG&E 2017 BP 2018	LG&E 2017 BP 2019	KU 2017 BP 2018	KU 2017 BP 2019
CFO pre-WC / Debt	18%	18%	27%	29%	26%	26%
CFO pre-WC + Interest / Interest	6.0	5.7	8.6	8.8	7.9	7.6
CFO pre-WC - Dividends / Debt	11%	15%	25%	22%	20%	17%
Debt to Capitalization	50%	49%	35%	34%	34%	34%

[1] Actuals represent a trailing 12 months.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2016	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — November 2017

($ Millions)

	11/30/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 12	$ 60	$ (48)	Primarily due to a decrease in cash at the non-utility companies.
Accounts Receivable (Trade)	376	386	(10)	
Inventory	272	266	6	
Regulatory Assets Current	24	26	(2)	
Prepayments and other current assets	68	36	31	Primarily due to higher accounts receivable related to refined coal, higher other accounts receivable and higher preliminary survey charges; which are offset partially by lower provision for accounts receivable bad debt.
Total Current Assets	751	774	(22)	
Property, Plant, and Equipment	11,939	12,120	(181)	
Intangible Assets	87	89	(2)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	797	927	(130)	Primarily due to pension funded status adjustments, decrease in ARO balances and market adjustments for interest rate swaps.
Goodwill	997	997	0	
Other Long-term Assets	60	80	(20)	Primarily due to lower collateral on interest rate swaps, lower prepaid insurance, lower primary survey and investigation charges, lower life insurance and other deferred debits and lower Cane Run 7 LTPC assets.
Total Assets	**$ 14,632**	**$ 14,988**	**$ (355)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 337	$ 215	$ 122	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	86	0	86	Dividends are considered declared and paid in the same month in the budget.
Customer Deposits	57	55	3	
Derivative Liability	4	6	(2)	
Accrued Taxes	74	48	26	Primarily due to timing of property tax payments expected to occur in the budget.
Regulatory Liabilities Current	8	19	(12)	Primarily lower due to lower fuel costs in the FAC liability.
Other Current Liabilities	267	192	75	Primarily due to ARO reclassification from long term to current in actuals versus the budget which assumed a static balance as of September 2016 when the budget was finalized and checks outstanding in actuals.
Total Current Liabilities	833	535	298	
Debt - Affiliated Company	579	713	(134)	Used tax settlements and dividends from utilities to pay down CEP reserves.
Debt [(1)]	4,870	5,168	(298)	
Total Debt	5,449	5,881	(432)	
Deferred Tax Liabilities	1,909	1,874	35	
Investment Tax Credit	129	129	0	
Accum Provision for Pension & Related Benefits	349	410	(61)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	261	353	(92)	Primarily due to ARO settlements, lower revaluations and reclassifications from long term to current.
Regulatory Liabilities Non Current	871	852	19	
Derivative Liability	22	27	(5)	
Other Liabilities	177	187	(10)	
Total Deferred Credits and Other Liabilities	3,719	3,832	(114)	
Equity	4,632	4,740	(108)	
Total Liabilities and Equity	**$ 14,632**	**$ 14,988**	**$ (355)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

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Balance Sheet - LG&E

November 2017

($ Millions)

	11/30/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 4	$ 5	$ (1)	
Accounts Receivable (Trade)	169	164	6	
Inventory	146	136	10	
Regulatory Assets Current	15	8	7	
Prepayments and other current assets	48	46	2	
Total Current Assets	382	358	24	
Property, Plant, and Equipment	5,236	5,314	(78)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	412	491	(79)	Primarily due to a pension funded status adjustment, decrease in ARO balance due to settlements and revaluation and market adjustments for interest rate swaps.
Goodwill	0	0	0	
Other Long-term Assets	10	21	(11)	Primarily due to lower collateral on interest rate swaps and lower preliminary survey and investigation charges.
Total Assets	**$ 6,047**	**$ 6,190**	**$ (143)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 203	$ 152	$ 51	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	42	42	(0)	
Customer Deposits	27	26	1	
Derivative Liability	4	6	(2)	
Accrued Taxes	39	34	5	
Regulatory Liabilities Current	3	3	(0)	
Other Current Liabilities	93	86	7	
Total Current Liabilities	411	349	61	
Debt - Affiliated Company	43	0	43	Increase due to notes payable to KU.
Debt [1]	1,820	1,981	(161)	
Total Debt	1,863	1,981	(118)	
Deferred Tax Liabilities	1,073	1,066	7	
Investment Tax Credit	35	35	(0)	
Accum Provision for Pension & Related Benefits	47	70	(22)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	86	94	(8)	
Regulatory Liabilities Non Current	340	341	(1)	
Derivative Liability	22	27	(5)	
Other Liabilities	85	90	(5)	
Total Deferred Credits and Other Liabilities	1,690	1,724	(34)	
Equity	2,084	2,136	(52)	
Total Liabilities and Equity	**$ 6,047**	**$ 6,190**	**$ (143)**	

[1] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

Case Nos. 2018-00294 and 2018-00295
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Balance Sheet - KU

November 2017

($ Millions)

	11/30/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 8	$ 5	$ 3	
Accounts Receivable (Trade)	206	221	(15)	
Inventory	126	130	(4)	
Regulatory Assets Current	9	18	(9)	
Prepayments and other current assets	86	21	65	Primarily due to higher accounts receivable related to refined coal, higher other accounts receivable, higher notes receivable from LG&E and higher preliminary survey charges; which are partially offset by lower accounts receivable from associated companies.
Total Current Assets	434	396	38	
Property, Plant, and Equipment	6,694	6,798	(103)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	383	438	(55)	Primarily due to a pension funded status adjustment and decrease in ARO balance due to lower actual accretion and depreciation expense versus budgeted.
Goodwill	0	0	0	
Other Long-term Assets	48	57	(9)	
Total Assets	**$ 7,573**	**$ 7,701**	**$ (129)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 179	$ 109	$ 70	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	55	50	5	
Customer Deposits	30	28	2	
Derivative Liability	0	0	0	
Accrued Taxes	37	26	10	Primarily due to timing of property tax payments expected to occur in the budget.
Regulatory Liabilities Current	5	16	(11)	Primarily lower due to lower fuel costs in the FAC liability.
Other Current Liabilities	122	59	63	Primarily due to ARO reclassification from long term to current in actuals versus the budget which assumed a static balance as of September 2016 when the budget was finalized and checks outstanding in actuals.
Total Current Liabilities	428	289	139	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,326	2,463	(137)	
Total Debt	2,326	2,463	(137)	
Deferred Tax Liabilities	1,289	1,322	(33)	
Investment Tax Credit	94	93	1	
Accum Provision for Pension & Related Benefits	38	66	(28)	Decrease primarily from funded status adjustment due to change in discount rate.
Asset Retirement Obligation	175	259	(84)	Primarily due to lower ARO revaluation and reclassification from long term to current.
Regulatory Liabilities Non Current	462	441	21	
Derivative Liability	0	0	0	
Other Liabilities	41	48	(7)	
Total Deferred Credits and Other Liabilities	2,099	2,229	(130)	
Equity	2,719	2,720	(1)	
Total Liabilities and Equity	**$ 7,573**	**$ 7,701**	**$ (129)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

PPL companies

Performance Report

December 2017

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Kentucky Regulated Dashboard — December 2017

	Current Month		YTD	
Safety	**Actual**	**PY**	**Actual**	**PY**
TCIR - Employees[1]	1.12	1.11	0.97	1.12
Employee lost-time incidents	1	1	9	5
Reliability	**Actual**	**Budget**	**Actual**	**Budget**
Generation Volumes	2,964	3,060	32,704	34,425
Utility EFOR	4.2%	5.0%	3.5%	5.0%
Utility EAF	93.3%	91.6%	84.1%	85.2%
Steam Fleet Commercial Availability	91.8%	93.0%	93.6%	93.0%
Combined SAIFI	0.05	0.06	0.84	1.03
Combined SAIDI (minutes)	3.90	5.56	75.41	93.20
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**
Residential	1,110	1,056	10,043	10,668
Commercial	651	656	7,818	7,882
Industrial	711	809	9,163	9,706
Municipals	155	148	1,755	1,846
Other	225	234	2,731	2,753
Off-System Sales	31	33	329	244
Total	2,883	2,937	31,839	33,098
Weather-Normalized Sales Growth			**TTM**	
Residential			0.30%	
Commercial			-1.22%	
Industrial			-2.24%	
Municipal			-3.69%	
Other			-3.38%	
Total			-1.36%	

	Current Month		YTD	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**
Electric Margins[2]	$171	$176	$1,856	$1,948
Gas Margins	$26	$25	$182	$183
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**
Total[2]	$132	$102	$995	$1,107
O&M ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**
O&M – Management View[2] [3]	$57	$58	$695	$749
O&M – GAAP View[2] [4]	$66	$69	$806	$864
Head Count	**Actual**	**Budget**	**Actual**	**Budget**
Full-time Employees	3,470	3,591	3,470	3,591
Other Metrics	**Actual**	**PY**	**Actual**	**PY**
Environmental Events	1	0	8	3
NERC Possible Violations[5]	0	0	8	5

	TTM	
Financial Metrics	**Actual**	**Budget**
Utility ROE[6]	9.8%	9.8%
Average Utility Capitalization ($ millions)	$8,971	$9,174

Variance Explanations

Lower margins YTD primarily due to lower sales volumes from unfavorable weather, resulting in lower retail electric base energy and demand revenue of $55 million, lower ECR revenue of $11 million and other offsetting margin components.

Lower O&M YTD primarily due to lower labor and burdens of $23 million, lower outside service expense of $12 million, lower storm and vegetation management expenses of $6 million, lower plant maintenance of $7 million and lower materials and other expenses of $6 million.

(1) Full year forecast amount shown represents target.

(2) Includes net impact of approved rate case outcome for deferred AMS Capital and O&M expenses, lower depreciation expense and the offsetting revenue reduction included in margins.

(3) Net of cost recovery mechanisms and variable costs of production.

(4) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses

(5) The possible violation issues for YTD Actual is believed to be minimal risk.

(6) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Major Developments

There were various filings made at the KPSC related to the effects of the Tax Cuts and Jobs Act on retail rates. In LKE's response, we disclosed the timing of our next rate review and suggested a mechanism to provide the net positive benefits of the Tax Act to customers in the interim only. Negotiations with parties to the case are ongoing.

On December 28, 2017, the U.S. District Court for the Eastern District of Kentucky entered an order granting our motion to dismiss the citizen suit filed by the Sierra Club and Kentucky Waterways Alliance against the EW Brown facility. This was a substantial victory because the case involved claims that, if we lost, could have had significant financial and operational exposure for the Company. The opinion is well reasoned and should provide a solid record in the event of an appeal by the plaintiffs. Any appeal would have to be filed on or before January 29, 2018.

The Company achieved outstanding key performance indicators during 2017. LKE achieved its lowest recordable injury rate in the company's history of 0.97. This figure was considerably lower than the 1.22 EEI top quartile level for the group of comparable utilities and closer to the EEI top-performer rate of 0.91. The Company's other operational metrics such as EFOR, SAIDI, and SAIFI were also well below budget and favorable to industry top quartile benchmarks.

The Utilities continue their strong base of excellent customer service. In the second of four surveys for the J.D. Power Electric Residential Study, KU and LG&E ranked first and second, respectively, among 13 utilities in the Midwest Midsize segment.

The Company installed four diesel generators at Cane Run Station and two diesel generators at Trimble County Station as part of an effort to modernize its black start capabilities. Each site has a building to house the generators, which are roughly each 3MW in size. The units are available and went into service at the end of December.

Significant Future Events

In January, LG&E and KU filed a Certificate of Public Convenience and Necessity with the KPSC to install 1.3 million advanced meters across its service territories. The total capital investment is projected to be about $320 million. In Kentucky, about 35 percent of all meters are advanced meters and, with LKE's proposal, this figure would grow to about 95 percent.

The Company continues to work on the deployment of 25 vehicles and 30 full time employees to assist in restoration efforts in Puerto Rico. The tentative schedule has employees arriving on the island around January 25.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — December 2017

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 259	$ 272	$ (13)	Due primarily to lower retail electric base energy and demand revenue and lower ECR revenue.
Gas Revenues	49	46	4	
Total Revenues	309	318	(9)	
Cost of Sales:				
Fuel Electric Costs	68	72	4	
Gas Supply Expenses	23	20	(3)	
Purchased Power	6	5	(1)	
Other Cost of Production	3	4	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	6	7	0	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	9	4	
Total Cost of Sales	112	117	5	
Gross Margin:				
Electric Margin	171	176	(5)	See explanations above.
Gas Margin	26	25	1	
Total Gross Margin	197	201	(4)	
O&M	57	58	2	
Depreciation & Amortization	33	36	3	
Taxes, Other than Income	5	5	(0)	
Other income (expense)	(0)	(1)	1	
EBIT	102	100	2	
Interest Expense	18	19	1	
Income from Ongoing Operations before income taxes	83	81	2	
Income Tax Expense	32	31	(2)	
Net Income (loss) from ongoing operations	**51**	**50**	**1**	
Special Item - (Non Operating Income)	(109)	0	(109)	Decrease primarily due to Tax Reform adjustment offset by the settlement of a WKE indemnification.
Discontinued Operations	(1)	0	(1)	
Net Income (loss)	$ (58)	$ 50	$ (109)	
KY Regulated Financing Costs	(3)	$ (3)	(0)	
KY Regulated Net Income	$ (61)	$ 48	$ (109)	
Earnings Per Share - Ongoing	$ 0.07	$ 0.07	$ 0.00	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — December 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,848	$ 3,017	$ (169)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	311	329	(17)	Due primarily to lower sales volumes driven by unfavorable weather in Q1.
Total Revenues	3,159	3,346	(187)	
Cost of Sales:				
Fuel Electric Costs	763	813	50	Primarily due to decreased generation as a result of unfavorable weather.
Gas Supply Expenses	117	135	18	Due primarily to lower gas usage as a result of unfavorable weather.
Purchased Power	61	60	(2)	
Other Cost of Production	37	41	4	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	74	74	(0)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	69	93	24	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates which is offset in margins.
Total Cost of Sales	1,122	1,216	94	
Gross Margin:				
Electric Margin	1,856	1,948	(92)	See explanations above.
Gas Margin	182	183	(0)	
Total Gross Margin	2,038	2,130	(93)	
O&M	695	749	54	Primarily due to lower labor and burdens, lower outside service expense, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	375	395	20	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Taxes, Other than Income	60	61	1	
Other income (expense)	(6)	(8)	1	
EBIT	901	917	(16)	
Interest Expense	215	217	2	
Income from Ongoing Operations before income taxes	686	700	(14)	
Income Tax Expense	261	267	6	
Net Income (loss) from ongoing operations	**425**	**433**	**(8)**	
Special Item - (Non Operating Income)	(109)	0	(109)	Decrease primarily due to Tax Reform adjustment offset by the settlement of a WKE indemnification.
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 316	$ 434	$ (117)	
KY Regulated Financing Costs	(30)	(30)	(0)	
KY Regulated Net Income	286	$ 404	$ (117)	
Earnings Per Share - Ongoing	$ 0.57	$ 0.58	$ (0.01)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E — December 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,144	$ 1,201	$ (57)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	311	329	(17)	Due primarily to lower sales volumes driven by unfavorable weather in Q1.
Total Revenues	1,455	1,530	(75)	
Cost of Sales:				
Fuel Electric Costs	298	304	6	
Gas Supply Expenses	117	135	18	Due primarily to lower gas usage as a result of unfavorable weather.
Purchased Power	50	56	5	Lower intercompany and market purchases driven by unfavorable weather.
Other Cost of Production	16	15	(1)	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	29	30	2	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	35	46	11	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates which is offset in margins.
Total Cost of Sales	545	587	42	
Gross Margin:				
Electric Margin	728	761	(33)	See explanations above.
Gas Margin	182	183	(0)	
Total Gross Margin	910	943	(33)	
O&M	310	342	33	Primarily due to lower labor and burdens, lower outside service expense, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	151	160	9	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Taxes, Other than Income	31	31	1	
Other income (expense)	(3)	(3)	0	
EBIT	416	406	10	
Interest Expense	70	71	2	
Income from Ongoing Operations before income taxes	346	335	11	
Income Tax Expense	132	128	(4)	
Net Income (loss) from ongoing operations	**$ 214**	**$ 207**	**$ 8**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Actual vs. Budget (YTD) - KU

December 2017

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,745	$ 1,870	$ (125)	Due primarily to lower sales volumes as a result of unfavorable weather and lower ECR revenues.
Gas Revenues	0	0	0	
Total Revenues	1,745	1,870	(125)	
Cost of Sales:				
Fuel Electric Costs	469	513	43	Primarily due to decreased generation as a result of unfavorable weather.
Gas Supply Expenses	0	0	0	
Purchased Power	48	54	5	Lower intercompany and market purchases driven by unfavorable weather.
Other Cost of Production	21	27	6	Primarily due to decreased generation as a result of unfavorable weather.
Mechanism - ECR, DSM & GLT - Operation and Maintenance	45	44	(2)	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	34	46	12	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Total Cost of Sales	618	683	66	
Gross Margin:				
Electric Margin	1,128	1,187	(59)	See explanations above.
Gas Margin	0	0	0	
Total Gross Margin	1,128	1,187	(59)	
O&M	358	388	30	Primarily due to lower labor and burdens, lower outside service expense, lower storm and vegetation management expenses, lower plant maintenance and lower materials.
Depreciation & Amortization	223	234	11	Primarily due to lower actual capital spending and in-service dates and the impact of the settled versus as filed depreciation rates, which is offset in margins.
Taxes, Other than Income	30	30	(0)	
Other income (expense)	(2)	(4)	2	
EBIT	514	531	(17)	
Interest Expense	97	96	(1)	
Income from Ongoing Operations before income taxes	418	435	(17)	
Income Tax Expense	159	165	6	
Net Income (loss) from ongoing operations	**$ 259**	**$ 270**	**$ (11)**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

O&M — December 2017

($ Millions)

	MTD Actual	MTD Budget	MTD Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	17	14	(2)	(0)	0	(1)	(1)	0
Project Engineering	0	0	0	0	0	0	0	(0)
Transmission	3	3	(1)	(0)	(0)	(0)	(0)	0
Energy Supply and Analysis	1	1	(0)	(0)	0	0	(0)	0
Electric Distribution	5	6	0	(0)	1	(0)	(0)	(0)
Gas Distribution	3	3	(0)	(0)	0	(0)	(0)	0
Advanced Metering System	0	1	0	0	0	0	0	(0)
Safety and Technical Training	0	0	(0)	0	(0)	(0)	(0)	(0)
Customer Services	8	8	0	0	0	(0)	(0)	(0)
SVP Operations Total	**39**	**36**	**(3)**	**0**	**1**	**(2)**	**(2)**	**(0)**
Audit Services	0	0	0	(0)	0	0	0	0
Controller	1	1	0	(0)	0	0	0	(0)
Supply Chain	0	0	0	0	0	0	0	0
Information Technology	4	5	0	0	(0)	0	0	0
Treasurer	2	2	0	0	0	0	(0)	0
State Regulation and Rates	0	0	0	(0)	0	0	0	0
Other	0	0	0	0	0	(0)	0	0
Chief Financial Officer Total	**8**	**9**	**1**	**0**	**(0)**	**0**	**0**	**0**
General Counsel	**2**	**3**	**1**	**(0)**	**0**	**(0)**	**0**	**1**
Human Resources	**1**	**1**	**0**	**0**	**(0)**	**0**	**(0)**	**0**
Corporate	**6**	**9**	**3**	**3**	**0**	**0**	**(0)**	**0**
Communication	**1**	**1**	**0**	**0**	**(0)**	**0**	**(0)**	**0**
Utility Total	**56**	**57**	**2**	**3**	**1**	**(2)**	**(2)**	**1**
Nonutility	**1**	**1**	**(0)**	**0**	**(0)**	**0**	**0**	**(0)**
O&M Total MTD	**57**	**58**	**2**	**4**	**1**	**(2)**	**(2)**	**1**

	YTD Actual	YTD Budget	YTD Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	199	217	18	5	(1)	7	10	(3)
Project Engineering	6	1	(5)	(0)	(0)	(4)	0	(1)
Transmission	32	34	2	0	1	1	(0)	1
Energy Supply and Analysis	13	13	0	0	0	(0)	(0)	0
Electric Distribution	66	74	8	1	11	(4)	1	1
Gas Distribution	35	35	0	1	0	(0)	(0)	(0)
Advanced Metering System	0	3	3	1	0	2	0	(0)
Safety and Technical Training	5	5	(0)	(0)	(0)	(0)	(0)	0
Customer Services	93	99	6	1	2	1	(0)	2
SVP Operations Total	**448**	**482**	**33**	**8**	**13**	**3**	**10**	**(0)**
Audit Services	2	2	0	0	0	0	0	0
Controller	9	9	0	(0)	(0)	0	0	0
Supply Chain	4	4	0	0	(0)	(0)	0	0
Information Technology	51	56	5	3	(1)	2	(0)	1
Treasurer	23	24	1	(0)	0	0	0	1
State Regulation and Rates	4	4	0	(0)	0	0	0	0
Other	2	2	0	1	0	(0)	0	0
Chief Financial Officer Total	**95**	**102**	**7**	**4**	**(1)**	**2**	**0**	**3**
General Counsel	**20**	**24**	**5**	**0**	**0**	**2**	**0**	**2**
Human Resources	**6**	**7**	**1**	**0**	**(0)**	**0**	**0**	**0**
Corporate	**93**	**108**	**15**	**14**	**0**	**1**	**(0)**	**1**
Communication	**6**	**7**	**1**	**0**	**0**	**0**	**0**	**0**
Utility Total	**668**	**731**	**63**	**27**	**12**	**8**	**10**	**6**
Nonutility	**27**	**18**	**(9)**	**(4)**	[illegible]	**(1)**	**(0)**	**(4)**
O&M Total YTD	**695**	**749**	**54**	**23**	**12**	**6**	**10**	**2**

Note: Schedules may not sum due to rounding.

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Financing Activities — December 2017

($ Millions)

Balance Sheet	YTD Actual		YTD Budget		YTD Variance	
PCB						
Beg Bal	$	898.8	$	898.8	$	0.0
End Bal		890.0		898.7		8.7
Ave Bal	**$**	**894.4**	**$**	**898.7**	**$**	**4.3**
Interest Exp	**$**	**15.2**	**$**	**11.9**	**$**	**(3.3)**
Rate		**1.68%**		**1.31%**		**-0.37%**
FMB/Sr Nts/Loan with PPL						
Beg Bal	$	4,210.0	$	4,210.0	$	0.0
End Bal		4,310.0		4,608.5		298.5
Ave Bal	**$**	**4,260.0**	**$**	**4,409.2**	**$**	**149.24**
Interest Exp	**$**	**183.6**	**$**	**187.7**	**$**	**4.1**
Rate		**4.25%**		**4.20%**		**-0.05%**
Short-term Debt						
Beg Bal	$	348.1	$	509.7	$	161.6
End Bal		468.9		530.2		61.3
Ave Bal (1)	**$**	**408.5**	**$**	**520.0**	**$**	**111.5**
Interest Exp	**$**	**6.0**	**$**	**6.9**	**$**	**0.9**
Rate		**1.90%**		**1.31%**		**-0.60%**
Unamortized Debt Expense Bonds						
Beg Bal	$	(44.0)	$	(43.2)	$	0.7
End Bal		(41.6)		(42.0)		(0.4)
Ave Bal	**$**	**(42.8)**	**$**	**(42.6)**	**$**	**0.2**
Total End Bal	**$**	**5,627.2**	**$**	**5,995.3**	**$**	**368.1**
Total Average Bal	**$**	**5,423.6**	**$**	**5,785.3**	**$**	**361.7**
Total Expense Excl I/C (2)	**$**	**215.1**	**$**	**217.2**	**$**	**2.1**
Rate		**3.88%**		**3.68%**		**-0.20%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use the average of the beginning and ending balances.
(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity		Borrowed(3)		Letters of Credit Issued		Unused Capacity		Money Pool Loans	
LKE	$	350	$	225			$	125		
LG&E		500		199				301	$	-
KU		598		45	$	198		355		-
TOTAL	$	1,448	$	469	$	198	$	781	$	-

(3) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2017 Actual YTD	LKE 2017 Budget YTD	LG&E 2017 Actual YTD	LG&E 2017 Budget YTD	KU 2017 Actual YTD	KU 2017 Budget YTD
CFO pre-WC / Debt	17%	17%	27%	25%	27%	27%
CFO pre-WC + Interest / Interest	5.5	5.7	8.2	8.0	7.6	8.0
CFO pre-WC - Dividends / Debt	11%	12%	19%	20%	17%	18%
Debt to Capitalization	52%	49%	39%	37%	37%	35%

Credit Metrics Moody's	LKE 2017 BP 2018	LKE 2017 BP 2019	LG&E 2017 BP 2018	LG&E 2017 BP 2019	KU 2017 BP 2018	KU 2017 BP 2019
CFO pre-WC / Debt	18%	18%	27%	29%	26%	26%
CFO pre-WC + Interest / Interest	6.0	5.7	8.6	8.8	7.9	7.6
CFO pre-WC - Dividends / Debt	11%	15%	25%	22%	20%	17%
Debt to Capitalization	50%	49%	35%	34%	34%	34%

(1) Actuals represent a trailing 12 months.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2017	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.
Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.
Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.
Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated

December 2017

($ Millions)

	12/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 30	$ 14	$ 16	Increase primarily due to timing of cash receipts at the utilities.
Accounts Receivable (Trade)	453	426	26	
Inventory	254	253	0	
Regulatory Assets Current	18	22	(4)	
Prepayments and other current assets	73	34	40	Primarily due to higher accounts receivable related to refined coal, higher other accounts receivable, higher prepayments and higher preliminary survey charges; which are offset partially by lower provision for accounts receivable bad debt.
Total Current Assets	827	750	78	
Property, Plant, and Equipment	12,029	12,170	(141)	
Intangible Assets	86	88	(2)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	795	929	(134)	Primarily due to a pension funded status adjustment, decrease in ARO balance due to settlements and revaluation and market adjustments for interest rate swaps.
Goodwill	997	997	0	
Other Long-term Assets	66	80	(13)	Primarily due to lower collateral on interest rate swaps, lower prepaid insurance, lower primary survey and investigation charges, lower life insurance and other deferred debits and lower Cane Run 7 LTPC assets; partially offset by higher Brown 6 and 7 LTSA assets.
Total Assets	**$ 14,802**	**$ 15,015**	**$ (213)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 344	$ 219	$ 126	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	58	55	3	
Derivative Liability	4	6	(2)	
Accrued Taxes	66	(4)	71	Primarily due to timing of property tax payments and federal tax settlement expected to occur in the budget.
Regulatory Liabilities Current	9	19	(10)	Primarily due to reclassification of ECR and FAC from Regulatory Assets Current.
Other Current Liabilities	279	207	72	Primarily due to ARO reclassification from long term to current in actuals versus the budget which assumed a static balance as of September 2016 when the budget was finalized and other accruals not included in the budget.
Total Current Liabilities	761	502	260	
Debt - Affiliated Company	625	845	(220)	Used tax settlements and dividends from utilities to pay down CEP reserves.
Debt [1]	5,002	5,150	(148)	
Total Debt	5,627	5,995	(368)	
Deferred Tax Liabilities	866	1,917	(1,051)	Decrease primarily due to recognition of excess deferred taxes as a result of tax reform. Amounts at Utilities were reclassed to regulatory liabilities.
Investment Tax Credit	129	129	0	
Accum Provision for Pension & Related Benefits	365	410	(45)	
Asset Retirement Obligation	271	351	(81)	Primarily due to ARO settlements, lower revaluations and reclassifications from long term to current.
Regulatory Liabilities Non Current	2,036	852	1,183	Primarily due to the reclassification from Deferred Tax Liabilities.
Derivative Liability	22	27	(5)	
Other Liabilities	162	184	(22)	Primarily due to a favorable settlement with BREC related to the HMPL lawsuit and lower provision for post retirement benefits.
Total Deferred Credits and Other Liabilities	3,850	3,870	(20)	
Equity	4,563	4,648	(85)	
Total Liabilities and Equity	**$ 14,802**	**$ 15,015**	**$ (213)**	

[1] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

December 2017

($ Millions)

	12/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 15	$ 5	$ 10	Increase primarily due to timing of cash receipts
Accounts Receivable (Trade)	209	187	22	Primarily due to variance between actual and budgeted Accounts Receivable lag factors.
Inventory	130	124	6	
Regulatory Assets Current	12	6	6	
Prepayments and other current assets	51	48	2	
Total Current Assets	416	370	46	
Property, Plant, and Equipment	5,278	5,341	(63)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	411	490	(79)	Primarily due to a pension funded status adjustment, decrease in ARO balance due to settlements and revaluation and market adjustments for interest rate swaps.
Goodwill	0	0	0	
Other Long-term Assets	11	20	(9)	
Total Assets	**$ 6,123**	**$ 6,228**	**$ (106)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 201	$ 154	$ 48	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	27	26	1	
Derivative Liability	4	6	(2)	
Accrued Taxes	25	0	24	Primarily due to timing of property tax payments expected to occur in the budget.
Regulatory Liabilities Current	3	3	0	
Other Current Liabilities	87	90	(3)	
Total Current Liabilities	348	279	69	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	1,907	1,966	(59)	
Total Debt	1,907	1,966	(59)	
Deferred Tax Liabilities	572	1,097	(526)	Primarily due to reclassification of excess deferred taxes as a result of tax reform to regulatory liability.
Investment Tax Credit	35	35	(0)	
Accum Provision for Pension & Related Benefits	45	69	(24)	
Asset Retirement Obligation	97	93	4	
Regulatory Liabilities Non Current	871	341	530	Primarily due to the reclassification from Deferred Tax Liabilities.
Derivative Liability	22	27	(5)	
Other Liabilities	86	89	(3)	
Total Deferred Credits and Other Liabilities	1,729	1,752	(23)	
Equity	2,139	2,231	(92)	
Total Liabilities and Equity	**$ 6,123**	**$ 6,228**	**$ (106)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

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Balance Sheet - KU | December 2017

($ Millions)

	12/31/2017	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 15	$ 5	$ 10	Increase primarily due to timing of cash receipts
Accounts Receivable (Trade)	243	239	4	
Inventory	123	130	(6)	
Regulatory Assets Current	6	16	(10)	Primarily due to reclassification of ECR and FAC to Regulatory Liabilities Current.
Prepayments and other current assets	47	20	27	Primarily due to higher accounts receivable related to refined coal, higher other accounts receivable and higher preliminary survey charges; which are partially offset by lower accounts receivable from associated companies.
Total Current Assets	434	410	24	
Property, Plant, and Equipment	6,742	6,820	(78)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	383	442	(59)	Primarily due to a pension funded status adjustment and decrease in ARO balance due to lower actual accretion and depreciation expense versus budgeted.
Goodwill	0	0	0	
Other Long-term Assets	52	57	(5)	
Total Assets	**$ 7,624**	**$ 7,742**	**$ (118)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 190	$ 115	$ 75	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	31	28	2	
Derivative Liability	0	0	0	
Accrued Taxes	19	0	18	Primarily due to timing of property tax payments expected to occur in the budget.
Regulatory Liabilities Current	6	16	(10)	Primarily due to reclassification of ECR and FAC from Regulatory Assets Current.
Other Current Liabilities	122	66	57	Primarily due to ARO reclassification from long term to current in actuals versus the budget which assumed a static balance as of September 2016 when the budget was finalized and checks outstanding in actuals.
Total Current Liabilities	368	226	142	
Debt - Affiliated Company	0	0	0	
Debt [1]	2,371	2,460	(89)	
Total Debt	2,371	2,460	(89)	
Deferred Tax Liabilities	691	1,360	(669)	Primarily due to reclassification of excess deferred taxes as a result of tax reform to regulatory liability.
Investment Tax Credit	94	93	1	
Accum Provision for Pension & Related Benefits	36	66	(30)	Decrease primarily from funded status adjustment.
Asset Retirement Obligation	174	258	(84)	Primarily due to lower ARO revaluation and reclassification from long term to current.
Regulatory Liabilities Non Current	1,096	442	655	Primarily due to the reclassification from Deferred Tax Liabilities.
Derivative Liability	0	0	0	
Other Liabilities	43	47	(3)	
Total Deferred Credits and Other Liabilities	2,135	2,266	(131)	
Equity	2,749	2,789	(40)	
Total Liabilities and Equity	**$ 7,624**	**$ 7,742**	**$ (118)**	

[1] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

KU and LG&E Combined
Reconciliation of Allowed Return to
12 months ended Dec-2017 Regulatory Return
and ROE from Ongoing Operations

Allowed Return [1]		9.88%	
Adjustments (net tax):			
Change in capitalization - non mechanism	-0.23%		Growth in capitalization (rate base) between rate cases does not earn a return
Change in ROE from average mechanism rate base growth	0.00%		Mechanisms have a real-time return
Change in weighted cost of debt	-0.06%		Higher interest rates and borrowing
Change in margins	-0.08%		Lower revenue
Change in allowed expenses	0.30%		Lower expense
		-0.06%	
Actual Regulated ROE		9.82%	

[1] Based on the most recent base rate filings with test years ending 6/30/18 KPSC, 12/31/16 FERC, 12/31/14 VA.
Note the allowed return is a blended rate of the previous authorized ROE of 10% after 7/1/16 and the current authorized ROE of 9.7% after 7/1/17

PPL companies

Performance Report

January 2018

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Kentucky Regulated Dashboard — January 2018

	Current Month		Full Year	
Safety	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees[1]	0.92	0.46	1.30	0.97
Employee lost-time incidents	0	0	8	9
Reliability	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,550	3,214	34,040	33,704
Utility EFOR	2.6%	5.0%	N/A	5.0%
Utility EAF	94.2%	92.9%	N/A	83.7%
Combined SAIFI	0.07	0.08	N/A	0.99
Combined SAIDI (minutes)	6.94	6.86	N/A	91.90
GwH Sales	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	1,342	1,156	10,689	10,502
Commercial	712	680	7,847	7,815
Industrial	757	794	9,284	9,321
Municipals	176	168	1,786	1,778
Other	235	245	2,812	2,822
Off-System Sales	226	26	349	150
Total	3,447	3,068	32,767	32,389
Weather-Normalized Sales Growth	**TTM**			
Residential	2.78%			
Commercial	-1.17%			
Industrial	-1.69%			
Municipal	-4.04%			
Other	-3.65%			
Total	-0.45%			

	Current Month		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$180	$166	$1,831	$1,831
Gas Margins	$27	$28	$185	$185
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$81	$96	$1,262	$1,277
O&M ($ millions)	**Actual**	**Budget**	**Forecast**	**Budget**
O&M – Management View[2]	$55	$59	$752	$752
O&M – GAAP View[3]	$65	$69	$869	$869
Head Count	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,460	3,582	3,593	3,597
Other Metrics	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	1	N/A	8
NERC Possible Violations[4]	0	1	N/A	8

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
Utility ROE[5]	10.3%	9.6%	9.6%
Average Utility Capitalization ($ millions)	$9,001	$9,527	$9,527

Variance Explanations

Higher margins YTD primarily due to higher sales volumes from favorable weather, resulting in higher retail electric base energy revenue of $12 million.

(1) Full year forecast amount shown represents target.

(2) Net of cost recovery mechanisms and variable costs of production.

(3) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses

(4) The possible violation issues for YTD Actual is believed to be minimal risk.

(5) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Major Developments

The Tax Act case settlement is progressing as planned and all indications suggest the KPSC is working toward an Order in the case.

KU established a new all-time weekend peak load of 4,560 MW's on January 6, 2018. LG&E and the Combined Utilities' system also set new winter weekend peak loads of 1,777 MW's and 6,337 MW's, respectively. In addition, all-time weekend total daily energy usage records were set for KU and the Combined Utilities' system, and a winter weekend record for LG&E.

LKE requested approval from the KPSC to modify the previously granted CPCN for Phase II of the Brown landfill. The request is driven by the announced retirements of Brown Units 1 and 2 which reduces the projected amount of coal combustion residuals ("CCR") produced at the site. As a result of these changes, Phase III of the landfill will also not be required. Additionally, the Company is required to cap and close any remaining surface area of the existing main pond not covered by the landfill or paved areas. The unit retirements have also resulted in a significant decrease in the projected cost for the CCR Rule Process Water System from the filed $71.7 million to $25.1 million. All of these modifications were assumed in the 2018 Business Plan. Construction on the Phase II landfill is expected to begin in August 2018 with commercial operation before the end of 2019.

The Company submitted, as planned, an application for a Certificate of Public Convenience and Necessity for the Advance Metering System.

Three of LG&E and KU's Research and Development projects have been honored by the Electric Power Research Institute ("EPRI"). The Company's energy storage site at Brown was recognized with a "Technology Transfer" award for applying EPRI methods and standards. LKE also received similar honors for a project that allows the Company to operate selective catalytic reduction (SCR) at lower loads and temperatures, and another one for conducting aquatic life studies designed to assess the impact of cooling water withdraw.

The Company was awarded an EEI Emergency Response Award for outstanding assistance with restoration efforts for Hurricanes Harvey and Irma.

The Archdiocese of Louisville has signed a contract with LKE and will become the Company's first Business Solar customer pending approval from the KPSC. LKE will own and operate the solar facility which will be a 30 kW roof-mounted array.

House Bill ("HB") 227 was introduced in the Kentucky Legislative Session and assigned to the House Natural Resources and Energy Committee where it was favorably voted out of committee. The next step is a full House floor vote. According to HB 227, new private solar customers will still be able to offset their energy use with private solar generation but, if the customer generates more energy than needed, the utility will purchase the energy at the same rate as it would pay any other qualified generator from which the utility would purchase energy (i.e. variable cost) versus the currently required all-in retail rate. The proposed legislation "grandfathers" in current net metering customers under their current plan for the next 25 years.

Significant Future Events

The Company continues to assist with restoration efforts in Puerto Rico as the crew has worked more than 7,000 hours without any safety incidents. A second team will replace the current crew around February 25th.

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — January 2018

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 294	$ 260	$ 34	Primarily due to higher sales volumes as a result of favorable weather.
Gas Revenues	57	57	0	
Total Revenues	351	317	34	
Cost of Sales:				
Fuel Electric Costs	94	74	(20)	Primarily due to increased generation as a result of favorable weather.
Gas Supply Expenses	30	29	(1)	
Purchased Power	5	5	0	
Other Cost of Production	4	3	(0)	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	6	6	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	6	0	
Total Cost of Sales	144	124	(21)	
Gross Margin:				
Electric Margin	180	166	15	See explanations above.
Gas Margin	27	28	(1)	
Total Gross Margin	207	194	14	
O&M	55	59	4	
Depreciation & Amortization	33	34	0	
Taxes, Other than Income	6	6	0	
Other income (expense)	(2)	(1)	(1)	
EBIT	111	94	17	
Interest Expense	19	19	1	
Income from Ongoing Operations before income taxes	92	74	18	
Income Tax Expense	20	19	(1)	
Net Income (loss) from ongoing operations	**73**	**56**	**17**	
Special Item - (Non Operating Income)	0	0	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 73	$ 56	$ 17	
KY Regulated Financing Costs	(3)	(3)	(0)	
KY Regulated Net Income	69	$ 53	$ 17	
Earnings Per Share - Ongoing	$ 0.10	$ 0.07	$ 0.03	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LG&E — January 2018

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 113	$ 99	$ 14	Primarily due to higher sales volumes as a result of favorable weather.
Gas Revenues	57	57	0	
Total Revenues	170	156	14	
Cost of Sales:				
Fuel Electric Costs	39	29	(10)	Primarily due to increased generation as a result of favorable weather.
Gas Supply Expenses	30	29	(1)	
Purchased Power	4	4	0	
Other Cost of Production	1	2	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	2	3	0	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	3	3	0	
Total Cost of Sales	79	69	(10)	
Gross Margin:				
Electric Margin	65	59	5	See explanations above.
Gas Margin	27	28	(1)	
Total Gross Margin	91	87	4	
O&M	25	26	1	
Depreciation & Amortization	14	14	0	
Taxes, Other than Income	3	3	0	
Other income (expense)	(1)	(1)	(1)	
EBIT	48	44	5	
Interest Expense	6	6	0	
Income from Ongoing Operations before income taxes	42	37	5	
Income Tax Expense	11	9	(1)	
Net Income (loss) from ongoing operations	**$ 31**	**$ 28**	**$ 4**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Actual vs. Budget (YTD) - KU — January 2018

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 192	$ 168	$ 24	Primarily due to higher sales volumes as a result of favorable weather.
Gas Revenues	0	0	0	
Total Revenues	192	168	24	
Cost of Sales:				
Fuel Electric Costs	60	45	(15)	Primarily due to increased generation as a result of favorable weather.
Gas Supply Expenses	0	0	0	
Purchased Power	7	8	1	
Other Cost of Production	2	2	(0)	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	4	4	0	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	3	3	0	
Total Cost of Sales	76	62	(14)	
Gross Margin:				
Electric Margin	116	106	9	See explanations above.
Gas Margin	0	0	0	
Total Gross Margin	116	106	9	
O&M	28	31	3	
Depreciation & Amortization	20	20	0	
Taxes, Other than Income	3	3	0	
Other income (expense)	(1)	(1)	0	
EBIT	64	52	12	
Interest Expense	8	8	0	
Income from Ongoing Operations before income taxes	56	44	12	
Income Tax Expense	14	11	(3)	
Net Income (loss) from ongoing operations	**$ 42**	**$ 33**	**$ 9**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

O&M								January 2018
($ Millions)								
	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	13	14	1	0	0	0	(0)	1
Project Engineering	0	0	0	0	0	0	0	0
Transmission	3	3	1	(0)	1	0	(0)	(0)
Energy Supply and Analysis	1	1	0	0	0	0	0	0
Electric Distribution	5	5	0	(0)	1	(1)	0	0
Gas Distribution	3	3	(0)	0	(0)	0	(0)	(0)
Advanced Metering System	0	0	0	0	0	0	0	(0)
Safety and Technical Training	1	1	(0)	0	(0)	0	(0)	(0)
Environmental	1	1	0	0	0	0	0	0
Customer Services	8	9	1	0	0	0	0	0
SVP Operations Total	**35**	**38**	**3**	**0**	**2**	**(0)**	**(0)**	**1**
Audit Services	0	0	0	0	0	0	0	0
Controller	1	1	0	0	0	0	(0)	0
Supply Chain	0	0	0	0	0	0	(0)	0
Information Technology	5	5	1	1	(0)	(0)	(0)	0
Treasurer	2	2	0	(0)	0	0	(0)	0
State Regulation and Rates	0	0	0	0	0	0	(0)	0
Other	0	0	(0)	0	0	(0)	0	0
Chief Financial Officer Total	**9**	**9**	**1**	**1**	**(0)**	**(0)**	**(0)**	**0**
General Counsel	**1**	**1**	**0**	**0**	**0**	**(0)**	**(0)**	**0**
Human Resources	**1**	**1**	**0**	**0**	**0**	**(0)**	**0**	**0**
Corporate	**8**	**8**	**(0)**	**(0)**	**0**	**0**	**(0)**	**0**
Communication	**1**	**1**	**(0)**	**(0)**	**0**	**0**	**(0)**	**0**
Utility Total	**54**	**57**	**4**	**1**	**2**	**(0)**	**(1)**	**2**
Nonutility	**2**	**2**	**0**	**0**	**(0)**	**(0)**	**0**	**0**
O&M Total YTD	**55**	**59**	**4**	**1**	**2**	**(0)**	**(1)**	**2**

Note: Schedules may not sum due to rounding.

Financing Activities — January 2018

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance
PCB			
Beg Bal	$ 890.0	$ 890.0	$ 0.0
End Bal	890.0	890.0	0.0
Ave Bal	**$ 890.0**	**$ 890.0**	**$ 0.0**
Interest Exp	**$ 1.2**	**$ 1.5**	**$ 0.2**
Rate	**1.62%**	**1.89%**	**0.27%**
FMB/Sr Nts/Loan with PPL			
Beg Bal	$ 4,310.0	$ 4,310.0	$ 0.0
End Bal	4,410.0	4,410.0	0.0
Ave Bal	**$ 4,360.0**	**$ 4,360.0**	**$ 0.0**
Interest Exp	**$ 15.5**	**$ 15.6**	**$ 0.1**
Rate	**4.14%**	**4.16%**	**0.02%**
Short-term Debt			
Beg Bal	$ 468.9	$ 468.9	$ 0.0
End Bal	469.2	432.1	(37.1)
Ave Bal (1)	**$ 469.0**	**$ 450.5**	**$ (18.5)**
Interest Exp	**$ 1.0**	**$ 1.4**	**$ 0.4**
Rate	**2.44%**	**3.49%**	**1.05%**
Unamortized Debt Expense Bonds			
Beg Bal	$ (41.6)	$ (41.6)	$ 0.0
End Bal	(41.2)	(41.3)	(0.0)
Ave Bal	**$ (41.4)**	**$ (41.4)**	**$ (0.0)**
Total End Bal	**$ 5,727.9**	**$ 5,690.8**	**$ (37.1)**
Total Average Bal	**$ 5,681.7**	**$ 5,659.0**	**$ (22.7)**
Total Expense Excl I/C (2)	**$ 18.7**	**$ 19.4**	**$ 0.7**
Rate	**3.79%**	**3.94%**	**0.15%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use an average monthly balance.
(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(3)	Letters of Credit Issued	Unused Capacity	Money Pool Loans
LKE	$ 350	$ 247		$ 103	
LG&E	500	124		376	$ 0
KU	598	98	$ 198	302	0
TOTAL	$ 1,448	$ 469	$ 198	$ 781	$ 0

(3) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2018 Actual YTD	LKE 2018 Budget YTD	LG&E 2018 Actual YTD	LG&E 2018 Budget YTD	KU 2018 Actual YTD	KU 2018 Budget YTD
CFO pre-WC / Debt	18%	18%	27%	27%	27%	27%
CFO pre-WC + Interest / Interest	5.7	5.6	8.4	8.3	7.8	7.7
CFO pre-WC - Dividends / Debt	11%	11%	18%	18%	18%	18%
Debt to Capitalization	52%	52%	39%	39%	37%	37%

Credit Metrics Moody's	LKE 2018 BP 2019	LKE 2018 BP 2020	LG&E 2018 BP 2019	LG&E 2018 BP 2020	KU 2018 BP 2019	KU 2018 BP 2020
CFO pre-WC / Debt	14%	14%	19%	19%	19%	20%
CFO pre-WC + Interest / Interest	4.4	4.4	5.8	5.6	5.7	5.7
CFO pre-WC - Dividends / Debt	10%	10%	11%	10%	10%	11%
Debt to Capitalization	53%	52%	38%	38%	38%	38%

[1] Actuals represent a trailing 12 months.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2017	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — January 2018

($ Millions)

	1/31/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 22	$ 14	$ 8	
Accounts Receivable (Trade)	526	488	38	
Inventory	226	232	(6)	
Regulatory Assets Current	14	13	2	
Prepayments and other current assets	77	79	(2)	
Total Current Assets	865	825	40	
Property, Plant, and Equipment	12,066	12,080	(14)	
Intangible Assets	85	85	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	794	794	(0)	
Goodwill	997	997	0	
Other Long-term Assets	69	67	2	
Total Assets	**$ 14,877**	**$ 14,850**	**$ 27**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 333	$ 332	$ 1	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	58	58	0	
Derivative Liability	4	4	(0)	
Accrued Taxes	78	86	(9)	
Regulatory Liabilities Current	39	20	19	Primarily due to increased off systems sales and higher than budgeted ECR regulatory liability.
Other Current Liabilities	263	296	(33)	Decrease primarily due to fluctuations in actuals related to miscellaneous liabilities and outstanding checks that are not incorporated in the budget as the budgeted balance is based on a static amount from December 2017.
Total Current Liabilities	775	797	(22)	
Debt - Affiliated Company	647	632	15	
Debt [(1)]	5,081	5,059	22	
Total Debt	5,728	5,691	37	
Deferred Tax Liabilities	863	866	(4)	
Investment Tax Credit	129	129	(0)	
Accum Provision for Pension & Related Benefits	262	259	3	
Asset Retirement Obligation	269	269	0	
Regulatory Liabilities Non Current	2,036	2,036	0	
Derivative Liability	19	22	(2)	
Other Liabilities	161	162	(1)	
Total Deferred Credits and Other Liabilities	3,739	3,742	(3)	
Equity	4,635	4,620	16	
Total Liabilities and Equity	**$ 14,877**	**$ 14,850**	**$ 27**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

January 2018

($ Millions)

	1/31/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 8	$ 5	$ 3	
Accounts Receivable (Trade)	239	225	14	
Inventory	112	111	0	
Regulatory Assets Current	7	10	(2)	
Prepayments and other current assets	49	54	(5)	
Total Current Assets	415	405	10	
Property, Plant, and Equipment	5,305	5,313	(8)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	408	409	(1)	
Goodwill	0	0	0	
Other Long-term Assets	12	11	1	
Total Assets	**$ 6,147**	**$ 6,145**	**$ 2**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 202	$ 199	$ 3	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	28	27	0	
Derivative Liability	4	4	(0)	
Accrued Taxes	34	36	(2)	
Regulatory Liabilities Current	20	9	11	Primarily due to increased off systems sales.
Other Current Liabilities	84	93	(9)	
Total Current Liabilities	373	368	4	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	1,932	1,937	(5)	
Total Debt	1,932	1,937	(5)	
Deferred Tax Liabilities	572	572	(0)	
Investment Tax Credit	35	35	(0)	
Accum Provision for Pension & Related Benefits	(8)	(10)	2	
Asset Retirement Obligation	96	97	(1)	
Regulatory Liabilities Non Current	872	871	1	
Derivative Liability	19	22	(2)	
Other Liabilities	87	86	1	
Total Deferred Credits and Other Liabilities	1,672	1,674	(1)	
Equity	2,170	2,166	4	
Total Liabilities and Equity	**$ 6,147**	**$ 6,145**	**$ 2**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

Balance Sheet - KU

January 2018

($ Millions)

	1/31/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 13	$ 5	$ 8	
Accounts Receivable (Trade)	286	262	24	
Inventory	114	121	(7)	
Regulatory Assets Current	7	3	4	
Prepayments and other current assets	51	50	0	
Total Current Assets	471	441	30	
Property, Plant, and Equipment	6,753	6,759	(6)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	384	383	1	
Goodwill	0	0	0	
Other Long-term Assets	54	53	1	
Total Assets	**$ 7,674**	**$ 7,649**	**$ 26**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 181	$ 180	$ 1	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	31	31	0	
Derivative Liability	0	0	0	
Accrued Taxes	20	29	(9)	
Regulatory Liabilities Current	19	11	7	
Other Current Liabilities	118	130	(12)	
Total Current Liabilities	369	381	(12)	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,425	2,398	27	
Total Debt	2,425	2,398	27	
Deferred Tax Liabilities	691	691	(0)	
Investment Tax Credit	94	94	(0)	
Accum Provision for Pension & Related Benefits	(10)	(10)	1	
Asset Retirement Obligation	173	172	2	
Regulatory Liabilities Non Current	1,097	1,097	(0)	
Derivative Liability	0	0	0	
Other Liabilities	44	43	0	
Total Deferred Credits and Other Liabilities	2,089	2,087	2	
Equity	2,791	2,782	9	
Total Liabilities and Equity	**$ 7,674**	**$ 7,649**	**$ 26**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

LG&E KU

PPL companies

Performance Report

February 2018

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Kentucky Regulated Dashboard

February 2018

	Current Month		YTD		Full Year	
Safety	Actual	PY	Actual	PY	Forecast	PY
TCIR - Employees[1]	1.45	1.47	1.21	1.02	1.30	0.97
Employee lost-time incidents	0	2	0	2	8	9
Reliability	Actual	Budget	Actual	Budget	Forecast	Budget
Generation Volumes	2,524	2,764	6,073	5,978	33,800	33,704
Utility EFOR	3.2%	5.0%	2.9%	5.0%	N/A	5.0%
Utility EAF	92.3%	91.3%	93.3%	92.1%	N/A	83.7%
Combined SAIFI	0.05	0.05	0.12	0.13	N/A	0.99
Combined SAIDI (minutes)	5.60	4.28	12.54	11.13	N/A	91.90
GwH Sales	Actual	Budget	Actual	Budget	Forecast	Budget
Residential	765	946	2,107	2,102	10,508	10,502
Commercial	572	605	1,284	1,285	7,814	7,815
Industrial	713	698	1,469	1,492	9,298	9,321
Municipals	132	145	308	313	1,773	1,778
Other	210	216	445	461	2,806	2,822
Off-System Sales	17	29	243	55	337	150
Total	2,409	2,640	5,856	5,709	32,536	32,389
Weather-Normalized Sales Growth			TTM			
Residential			2.04%			
Commercial			-0.44%			
Industrial			-0.67%			
Municipal			-4.03%			
Other			-2.92%			
Total			-0.14%			

	Current Month		YTD		Full Year	
Margins ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Electric Margins	$141	$151	$322	$317	$1,831	$1,831
Gas Margins	$22	$25	$49	$53	$185	$185
Capital Expenditures ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Total	$82	$93	$164	$189	$1,268	$1,277
O&M ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
O&M – Management View[2]	$60	$62	$115	$121	$752	$752
O&M – GAAP View[3]	$67	$70	$132	$139	$869	$869
Head Count	Actual	Budget	Actual	Budget	Forecast	Budget
Full-time Employees	3,452	3,581	3,452	3,581	3,586	3,597
Other Metrics	Actual	PY	Actual	PY	Forecast	PY
Environmental Events	0	1	0	2	N/A	8
NERC Possible Violations[4]	3	0	3	1	N/A	8

	TTM	Full Year	
Financial Metrics	Actual	Forecast	Budget
Utility ROE[5]	10.4%	9.6%	9.6%
Average Utility Capitalization ($ millions)	$9,026	$9,527	$9,527

Variance Explanations

Lower MTD margins primarily due to lower sales volumes from unfavorable weather, resulting in lower retail electric base energy revenue of $12 million.

Lower YTD O&M primarily due to lower storm and bad debt expense and timing of plant maintenance and other costs.

(1) Full year forecast amount shown represents target.

(2) Net of cost recovery mechanisms and variable costs of production.

(3) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses

(4) The possible violation issues for YTD Actual is believed to be minimal risk.

(5) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Major Developments

The month of February brought very warm and wet weather across the service territories. On February 20, Louisville and Lexington recorded all-time February high temperatures of 82 and 81 degrees. Ohio River flooding has been the worst in the Louisville area since 1997 and required both LKE's gas and electric businesses to proactively turn-off certain electric and gas customers.

The KPSC approved LKE's first Business Solar customer contract. The contract is with the Archdiocese of Louisville and LKE will own and operate the solar facility which will be a 30 kW roof-mounted array.

The KPSC approved LG&E and KU's (as well as Duke Energy KY and East Kentucky Power Cooperative's) participation in Regional Equipment Sharing for Transmission Outage Restoration (RESTORE), including the terms of potential asset transfers under the arrangement.

The Company continues to assist with restoration efforts in Puerto Rico. The first crew worked more than 17,000 hours without any recordable safety incidents and only one first aid case. A second team was dispatched and will return around April 6.

Significant Future Events

The KPSC issued an Order including a revised procedural schedule for the Advanced Metering Systems (AMS) case. The first round of data requests will be received April 2, with responses due April 13. Intervenor testimony will be filed May 18, and the Company's rebuttal testimony will be filed June 15. A formal hearing has not been scheduled, but would be expected early in the third quarter.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — February 2018

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 219	$ 234	$ (14)	Due primarily to lower sales volumes as a result of unfavorable weather.
Gas Revenues	40	51	(11)	Due primarily to lower sales volumes as a result of unfavorable weather.
Total Revenues	259	284	(26)	
Cost of Sales:				
Fuel Electric Costs	61	64	3	
Gas Supply Expenses	17	25	8	Due primarily to lower gas volumes as a result of unfavorable weather.
Purchased Power	5	5	0	
Other Cost of Production	3	3	(0)	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	4	5	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	6	0	
Total Cost of Sales	96	108	12	
Gross Margin:				
Electric Margin	141	151	(10)	See explanations above.
Gas Margin	22	25	(3)	
Total Gross Margin	163	176	(13)	
O&M	60	62	2	
Depreciation & Amortization	34	34	0	
Taxes, Other than Income	5	6	0	
Other income (expense)	(1)	(1)	(0)	
EBIT	63	74	(11)	
Interest Expense	18	19	1	
Income from Ongoing Operations before income taxes	45	55	(10)	
Income Tax Expense	10	14	4	
Net Income (loss) from ongoing operations	**35**	**41**	**(6)**	
Special Item - (Non Operating Income)	0	0	0	
Discontinued Operations	0	0	0	
Net Income (loss)	$ 35	$ 41	$ (6)	
KY Regulated Financing Costs	(3)	$ (3)	(0)	
KY Regulated Net Income	$ 32	$ 38	$ (6)	
Earnings Per Share - Ongoing	$ 0.05	$ 0.05	$ (0.01)	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LKE Consolidated

February 2018

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 513	$ 494	$ 20	Due primarily to higher off-system sales revenue in January related to favorable weather and higher than budgeted YTD fuel recovery.
Gas Revenues	97	108	(11)	Due primarily to lower sales volumes as a result of unfavorable weather in February.
Total Revenues	610	602	8	
Cost of Sales:				
Fuel Electric Costs	155	138	(17)	Due primarily to increased fuel costs in January to source off-system sales and higher than budgeted YTD fuel prices.
Gas Supply Expenses	47	54	7	Due primarily to lower gas volumes as a result of unfavorable weather in February.
Purchased Power	9	10	1	
Other Cost of Production	7	7	(0)	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	10	11	2	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	12	12	0	
Total Cost of Sales	240	232	(8)	
Gross Margin:				
Electric Margin	322	317	5	See explanations above.
Gas Margin	49	53	(4)	
Total Gross Margin	370	370	0	
O&M	115	121	6	Lower primarily due to lower storm and bad debt expense and timing of plant maintenance and other costs.
Depreciation & Amortization	67	67	0	
Taxes, Other than Income	11	11	0	
Other income (expense)	(3)	(2)	(1)	
EBIT	174	168	6	
Interest Expense	37	39	2	
Income from Ongoing Operations before income taxes	137	129	8	
Income Tax Expense	30	33	3	
Net Income (loss) from ongoing operations	**108**	**97**	**11**	
Special Item - (Non Operating Income)	0	0	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 108	$ 97	$ 11	
KY Regulated Financing Costs	(6)	(6)	(0)	
KY Regulated Net Income	101	$ 91	$ 11	
Earnings Per Share - Ongoing	$ 0.15	$ 0.12	$ 0.02	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E — February 2018

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 197	$ 187	$ 10	Due primarily to higher off-system sales revenue in January related to favorable weather and higher than budgeted YTD fuel recovery.
Gas Revenues	97	108	(11)	Due primarily to lower sales volumes as a result of unfavorable weather in February.
Total Revenues	294	295	(1)	
Cost of Sales:				
Fuel Electric Costs	62	55	(7)	Due primarily to increased fuel costs in January to source off-system sales and higher than budgeted YTD fuel prices.
Gas Supply Expenses	47	54	7	Due primarily to lower gas volumes as a result of unfavorable weather in February.
Purchased Power	7	7	(0)	
Other Cost of Production	3	3	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	4	5	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	5	5	0	
Total Cost of Sales	128	129	0	
Gross Margin:				
Electric Margin	117	114	4	
Gas Margin	49	53	(4)	
Total Gross Margin	166	166	(0)	
O&M	50	51	1	
Depreciation & Amortization	27	27	0	
Taxes, Other than Income	6	6	0	
Other income (expense)	(2)	(1)	(1)	
EBIT	81	80	0	
Interest Expense	12	13	1	
Income from Ongoing Operations before income taxes	69	68	1	
Income Tax Expense	17	17	(0)	
Net Income (loss) from ongoing operations	**$ 51**	**$ 50**	**$ 1**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Actual vs. Budget (YTD) - KU

February 2018

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 330	$ 319	$ 11	Due primarily to higher off-system sales revenue in January related to favorable weather and higher than budgeted YTD fuel recovery.
Gas Revenues	0	0	0	
Total Revenues	330	319	11	
Cost of Sales:				
Fuel Electric Costs	98	84	(14)	Due primarily to increased fuel costs in January to source off-system sales and higher than budgeted YTD fuel prices.
Gas Supply Expenses	0	0	0	
Purchased Power	11	14	3	
Other Cost of Production	4	4	(0)	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	6	7	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	7	0	
Total Cost of Sales	125	116	(10)	
Gross Margin:				
Electric Margin	204	204	1	
Gas Margin	0	0	0	
Total Gross Margin	204	204	1	
O&M	56	61	5	Lower primarily due to lower storm and bad debt expense and timing of plant maintenance and other costs.
Depreciation & Amortization	40	40	0	
Taxes, Other than Income	5	5	0	
Other income (expense)	(1)	(1)	0	
EBIT	103	97	6	
Interest Expense	16	17	0	
Income from Ongoing Operations before income taxes	87	80	7	
Income Tax Expense	22	20	(2)	
Net Income (loss) from ongoing operations	**$ 65**	**$ 60**	**$ 5**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

O&M								February 2018

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	13	14	1	(0)	0	0	(1)	1
Project Engineering	0	0	0	(0)	0	(0)	0	0
Transmission	3	3	0	(0)	1	(0)	(0)	(0)
Energy Supply and Analysis	1	1	0	(0)	0	0	0	0
Electric Distribution	6	6	(0)	(0)	1	(1)	0	(0)
Gas Distribution	3	3	(0)	0	(0)	(0)	(0)	(0)
Advanced Metering System	0	0	0	0	0	0	0	(0)
Safety and Technical Training	0	0	0	(0)	0	0	(0)	0
Environmental	1	1	0	(0)	0	0	0	0
Customer Services	7	8	1	(0)	(0)	0	0	1
SVP Operations Total	**34**	**36**	**2**	**(0)**	**1**	**(0)**	**(1)**	**1**
Audit Services	0	0	0	0	0	0	0	(0)
Controller	1	1	(0)	(0)	0	0	(0)	0
Supply Chain	0	0	(0)	(0)	0	(0)	(0)	0
Information Technology	4	5	0	0	(0)	0	0	0
Treasurer	2	2	(0)	(0)	0	0	0	(0)
State Regulation and Rates	0	0	0	0	0	0	0	(0)
Other	0	0	0	0	0	(0)	0	0
Chief Financial Officer Total	**8**	**8**	**(0)**	**0**	**(0)**	**(0)**	**(0)**	**(0)**
General Counsel	**1**	**1**	**(0)**	**(0)**	**0**	**(0)**	**0**	**0**
Human Resources	**1**	**1**	**(0)**	**(0)**	**0**	**(0)**	**(0)**	**0**
Corporate	**7**	**8**	**1**	**1**	**0**	**0**	**0**	**(0)**
Communication	**1**	**1**	**0**	**(0)**	**0**	**(0)**	**0**	**0**
Utility Total	**52**	**55**	**3**	**0**	**1**	**(0)**	**(0)**	**2**
Nonutility	**8**	**7**	**(1)**	**(2)**	**0**	**(0)**	**0**	**1**
O&M Total MTD	**60**	**62**	**2**	**(1)**	**1**	**(1)**	**(0)**	**2**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	27	29	2	0	1	0	(1)	1
Project Engineering	0	0	0	0	0	(0)	0	0
Transmission	6	6	1	(0)	1	(0)	(0)	(0)
Energy Supply and Analysis	2	2	0	0	0	0	0	0
Electric Distribution	11	11	0	(0)	2	(1)	0	0
Gas Distribution	6	6	(0)	0	(0)	0	(0)	(0)
Advanced Metering System	0	0	0	0	0	0	0	(0)
Safety and Technical Training	1	1	0	(0)	(0)	0	(0)	0
Environmental	1	1	0	(0)	0	0	0	0
Customer Services	15	17	1	(0)	0	0	0	1
SVP Operations Total	**69**	**74**	**5**	**0**	**3**	**(0)**	**(1)**	**2**
Audit Services	0	0	0	0	0	0	0	(0)
Controller	1	1	0	0	0	0	(0)	0
Supply Chain	1	1	0	(0)	0	(0)	(0)	0
Information Technology	9	10	1	1	(0)	0	(0)	0
Treasurer	4	4	(0)	(0)	0	0	(0)	(0)
State Regulation and Rates	1	1	0	0	0	0	(0)	0
Other	0	0	(0)	0	0	(0)	0	0
Chief Financial Officer Total	**17**	**18**	**1**	**1**	**(0)**	**(0)**	**(0)**	**0**
General Counsel	**3**	**2**	**(0)**	**0**	**0**	**(0)**	**0**	**0**
Human Resources	**1**	**1**	**0**	**0**	**0**	**(0)**	**0**	**0**
Corporate	**15**	**16**	**1**	**1**	**0**	**0**	**0**	**0**
Communication	**1**	**1**	**0**	**(0)**	**0**	**(0)**	**0**	**0**
Utility Total	**106**	**112**	**6**	**1**	**3**	**(1)**	**(1)**	**3**
Nonutility	**10**	**9**	**(1)**	**(1)**	**(0)**	**(0)**	**0**	**1**
O&M Total YTD	**115**	**121**	**6**	**0**	**3**	**(1)**	**(1)**	**4**

Note: Schedules may not sum due to rounding.

Case Nos. 2018-00294 and 2018-00295
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Financing Activities — February 2018

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance
PCB			
Beg Bal	$ 890.0	$ 890.0	$ 0.0
End Bal	890.0	890.0	0.0
Ave Bal	**$ 890.0**	**$ 890.0**	**$ 0.0**
Interest Exp	**$ 2.4**	**$ 2.9**	**$ 0.5**
Rate	**1.63%**	**1.99%**	**0.36%**
FMB/Sr Nts/Loan with PPL			
Beg Bal	$ 4,310.0	$ 4,310.0	$ 0.0
End Bal	4,410.0	4,410.0	0.0
Ave Bal	**$ 4,360.0**	**$ 4,360.0**	**$ 0.0**
Interest Exp	**$ 31.1**	**$ 31.3**	**$ 0.2**
Rate	**4.34%**	**4.36%**	**0.03%**
Short-term Debt			
Beg Bal	$ 468.9	$ 468.9	$ 0.0
End Bal	401.8	394.9	(6.9)
Ave Bal (1)	**$ 435.3**	**$ 431.9**	**$ (3.5)**
Interest Exp	**$ 1.8**	**$ 2.6**	**$ 0.8**
Rate	**2.49%**	**3.71%**	**1.22%**
Unamortized Debt Expense Bonds			
Beg Bal	$ (41.6)	$ (41.6)	$ 0.0
End Bal	(40.9)	(40.9)	(0.0)
Ave Bal	**$ (41.3)**	**$ (41.3)**	**$ (0.0)**
Total End Bal	**$ 5,660.9**	**$ 5,653.9**	**$ (6.9)**
Total Average Bal	**$ 5,665.9**	**$ 5,657.3**	**$ (8.5)**
Total Expense Excl I/C (2)	**$ 37.0**	**$ 38.6**	**$ 1.6**
Rate	**3.96%**	**4.13%**	**0.18%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use an average monthly balance.
(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(3)	Letters of Credit Issued	Unused Capacity	Money Pool Loans
LKE	$ 350	$ 240		$ 110	
LG&E	500	110		390	$ 0
KU	598	52	$ 198	348	0
TOTAL	$ 1,448	$ 402	$ 198	$ 848	$ 0

(3) LG&E and KU borrowed amounts represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2018 Actual YTD	LKE 2018 Budget YTD	LG&E 2018 Actual YTD	LG&E 2018 Budget YTD	KU 2018 Actual YTD	KU 2018 Budget YTD
CFO pre-WC / Debt	18%	18%	28%	28%	28%	28%
CFO pre-WC + Interest / Interest	5.7	5.7	8.4	8.4	7.9	7.8
CFO pre-WC - Dividends / Debt	11%	11%	18%	18%	19%	19%
Debt to Capitalization	52%	51%	38%	38%	36%	36%

Credit Metrics Moody's	LKE 2018 BP 2019	LKE 2018 BP 2020	LG&E 2018 BP 2019	LG&E 2018 BP 2020	KU 2018 BP 2019	KU 2018 BP 2020
CFO pre-WC / Debt	14%	14%	19%	19%	19%	20%
CFO pre-WC + Interest / Interest	4.4	4.4	5.8	5.6	5.7	5.7
CFO pre-WC - Dividends / Debt	10%	10%	11%	10%	10%	11%
Debt to Capitalization	53%	52%	38%	38%	38%	38%

[1] Actuals represent a trailing 12 months.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2017	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — February 2018

($ Millions)

	2/28/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 20	$ 14	$ 6	
Accounts Receivable (Trade)	462	469	(7)	
Inventory	209	219	(10)	
Regulatory Assets Current	14	3	10	Primarily due to ECR regulatory asset reclassification.
Prepayments and other current assets	70	76	(6)	
Total Current Assets	774	781	(7)	
Property, Plant, and Equipment	12,105	12,129	(24)	
Intangible Assets	85	85	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	794	793	1	
Goodwill	997	997	0	
Other Long-term Assets	79	73	6	
Total Assets	**$ 14,835**	**$ 14,859**	**$ (24)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 292	$ 328	$ (36)	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	59	58	1	
Derivative Liability	4	4	(0)	
Accrued Taxes	75	76	(0)	
Regulatory Liabilities Current	49	29	20	Primarily due to increased off systems sales and ECR regulatory asset reclassification.
Other Current Liabilities	282	309	(27)	
Total Current Liabilities	761	804	(43)	
Debt - Affiliated Company	640	640	0	
Debt [(1)]	5,021	5,014	7	
Total Debt	5,661	5,654	7	
Deferred Tax Liabilities	861	866	(5)	
Investment Tax Credit	129	129	(0)	
Accum Provision for Pension & Related Benefits	273	258	15	
Asset Retirement Obligation	268	267	1	
Regulatory Liabilities Non Current	2,035	2,035	(0)	
Derivative Liability	18	21	(3)	
Other Liabilities	159	163	(3)	
Total Deferred Credits and Other Liabilities	3,743	3,739	4	
Equity	4,670	4,662	8	
Total Liabilities and Equity	**$ 14,835**	**$ 14,859**	**$ (24)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

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Balance Sheet - LG&E

February 2018

($ Millions)

	2/28/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 8	$ 5	$ 3	
Accounts Receivable (Trade)	208	217	(9)	
Inventory	99	98	1	
Regulatory Assets Current	9	5	4	
Prepayments and other current assets	41	52	(11)	Primarily due to lower accounts receivable from associated companies, lower other accounts receivable and lower clearing accounts not forecasted.
Total Current Assets	365	377	(12)	
Property, Plant, and Equipment	5,333	5,346	(14)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	407	408	(1)	
Goodwill	0	0	0	
Other Long-term Assets	21	13	8	
Total Assets	**$ 6,132**	**$ 6,152**	**$ (20)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 177	$ 197	$ (20)	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	28	27	0	
Derivative Liability	4	4	(0)	
Accrued Taxes	26	27	(1)	
Regulatory Liabilities Current	25	13	11	Primarily due to higher than budgeted off systems sales, and ECR regulatory asset reclassification.
Other Current Liabilities	88	97	(9)	
Total Current Liabilities	346	366	(19)	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	1,918	1,925	(7)	
Total Debt	1,918	1,925	(7)	
Deferred Tax Liabilities	572	572	(0)	
Investment Tax Credit	35	35	(0)	
Accum Provision for Pension & Related Benefits	1	(11)	12	Difference due to reclassification of prepaid pension balance to other long term assets.
Asset Retirement Obligation	95	97	(2)	
Regulatory Liabilities Non Current	872	871	1	
Derivative Liability	18	21	(3)	
Other Liabilities	86	87	(1)	
Total Deferred Credits and Other Liabilities	1,678	1,672	6	
Equity	2,190	2,189	1	
Total Liabilities and Equity	**$ 6,132**	**$ 6,152**	**$ (20)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

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Balance Sheet - KU

February 2018

($ Millions)

	2/28/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 12	$ 5	$ 7	
Accounts Receivable (Trade)	253	252	2	
Inventory	109	121	(11)	
Regulatory Assets Current	4	(2)	6	
Prepayments and other current assets	45	49	(4)	
Total Current Assets	424	425	(1)	
Property, Plant, and Equipment	6,764	6,775	(10)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	385	383	2	
Goodwill	0	0	0	
Other Long-term Assets	64	56	7	
Total Assets	**$ 7,649**	**$ 7,651**	**$ (2)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 145	$ 176	$ (30)	Primarily due to timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	31	31	0	
Derivative Liability	0	0	0	
Accrued Taxes	29	31	(1)	
Regulatory Liabilities Current	25	16	8	
Other Current Liabilities	128	138	(10)	
Total Current Liabilities	358	391	(33)	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,379	2,365	14	
Total Debt	2,379	2,365	14	
Deferred Tax Liabilities	691	691	(0)	
Investment Tax Credit	93	94	(0)	
Accum Provision for Pension & Related Benefits	0	(11)	11	Difference due to reclassification of prepaid pension balance to other long term assets.
Asset Retirement Obligation	173	170	3	
Regulatory Liabilities Non Current	1,097	1,098	(1)	
Derivative Liability	0	0	0	
Other Liabilities	43	44	(1)	
Total Deferred Credits and Other Liabilities	2,098	2,086	12	
Equity	2,814	2,810	5	
Total Liabilities and Equity	**$ 7,649**	**$ 7,651**	**$ (2)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

PPL companies

Performance Report

March 2018

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Kentucky Regulated Dashboard — March 2018

	Current Month		YTD		Full Year	
Safety	Actual	PY	Actual	PY	Forecast	PY
TCIR - Employees[(1)]	0.78	1.06	1.02	1.03	1.30	0.97
Employee lost-time incidents	1	0	1	2	8	9
Reliability	Actual	Budget	Actual	Budget	Forecast	Budget
Generation Volumes	2,680	2,598	8,753	8,576	33,881	33,704
Utility EFOR	2.9%	5.0%	2.9%	5.0%	N/A	5.0%
Utility EAF	72.1%	63.2%	86.0%	82.2%	N/A	83.7%
Combined SAIFI	0.05	0.06	0.17	0.20	N/A	0.99
Combined SAIDI (minutes)	5.80	5.65	18.39	16.79	N/A	91.90
GwH Sales	Actual	Budget	Actual	Budget	Forecast	Budget
Residential	894	852	3,002	2,955	10,550	10,502
Commercial	647	591	1,931	1,876	7,870	7,815
Industrial	737	719	2,206	2,211	9,316	9,321
Municipals	141	148	449	461	1,766	1,778
Other	225	215	670	676	2,816	2,822
Off-System Sales	14	16	257	72	335	150
Total	2,658	2,541	8,514	8,250	32,653	32,389
Weather-Normalized Sales Growth			TTM			
Residential			0.77%			
Commercial			-0.25%			
Industrial			-1.74%			
Municipal			-4.23%			
Other			-2.48%			
Total			-0.78%			

	Current Month		YTD		Full Year	
Margins ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Electric Margins	$144	$146	$466	$463	$1,819	$1,831
Gas Margins	$20	$20	$69	$73	$182	$185
Capital Expenditures ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
Total	$88	$102	$252	$290	$1,268	$1,277
O&M ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
O&M – Management View[(2)]	$65	$66	$181	$187	$752	$752
O&M – GAAP View[(3)]	$73	$74	$205	$214	$861	$869
Head Count	Actual	Budget	Actual	Budget	Forecast	Budget
Full-time Employees	3,436	3,592	3,436	3,592	3,596	3,597
Other Metrics	Actual	PY	Actual	PY	Forecast	PY
Environmental Events	0	0	0	2	N/A	8
NERC Possible Violations[(4)]	0	2	3	3	N/A	8

	TTM	Full Year	
Financial Metrics	Actual	Forecast	Budget
Utility ROE[(5)]	10.6%	9.6%	9.6%
Average Utility Capitalization ($ millions)	$9,063	$9,571	$9,527

Variance Explanations

Lower YTD O&M primarily due to lower storm and bad debt expense and timing of plant maintenance and other costs.

(1) Full year forecast amount shown represents target.

(2) Net of cost recovery mechanisms and variable costs of production.

(3) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses

(4) The possible violation issues for YTD Actual is believed to be minimal risk.

(5) Excludes goodwill and other purchase accounting adjustments.

Major Developments

On March 20, 2018, the KPSC issued an order approving, with certain modifications, the settlement agreement in the Tax Cuts and Jobs Act ("TCJA") proceeding. Those modifications increased the estimated credit for customers by approximately $27 million. LG&E gas rate reductions were not modified significantly from the settlement agreement. On March 26, 2018, LG&E and KU filed a petition for reconsideration and request for hearing with the KPSC, taking exception with the KPSC's modifications and the process, and also requested certain relief from implementing the amounts represented by the additional reductions until the matter is fully resolved. On March 28, 2018, the KPSC issued an Order granting LKE's request for rehearing and amending its previous Order by suspending the approved rates, allowing LG&E and KU, on an interim basis, to return savings related to the TCJA at the rates agreed to in the settlement. A procedural schedule was issued and the Company's direct testimony was filed on April 6. A formal hearing on the matter is scheduled for May 24.

The KPSC approved PPL's proposal to create two new holding companies positioned between the corporation and its utilities. A similar restructuring proposal remains before the Pennsylvania Public Utility Commission (PUC) for approval.

The KPSC issued an order in LG&E's gas franchise dispute with Louisville Metro and ruled in LG&E's favor on all issues. Specifically, the order found that the franchise fee should be recovered as a separate line item on customers' bills and should be charged only to those customers within the jurisdiction of the municipality setting the franchise fee. As a result, no such franchise fee will be collected because of a provision in the current franchise agreement with Louisville Metro that the fee would be zero in the event the KPSC ruled in LG&E's favor.

On March 22, 2018, KU reached a settlement agreement regarding its ongoing rate case in Virginia. New rates, inclusive of TCJA impacts, will be effective June 1, 2018 and do not have a significant impact on KU. The settlement agreement is subject to review and approval by the VSCC.

On the last day of the legislative session, HB 227 (net metering reform) was effectively eliminated from passage as the Senate recommitted the bill to the Natural Resources Committee.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated

March 2018

($ Millions)

	MTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 225	$ 225	$ (1)	
Gas Revenues	38	38	0	
Total Revenues	263	263	(1)	
Cost of Sales:				
Fuel Electric Costs	62	61	(1)	
Gas Supply Expenses	17	17	0	
Purchased Power	5	6	0	
Other Cost of Production	3	3	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	5	5	0	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	6	0	
Total Cost of Sales	98	98	(0)	
Gross Margin:				
Electric Margin	144	146	(1)	
Gas Margin	20	20	0	
Total Gross Margin	165	166	(1)	
O&M	65	66	1	
Depreciation & Amortization	34	34	0	
Taxes, Other than Income	6	6	(0)	
Other income (expense)	2	(1)	4	
EBIT	62	59	4	
Interest Expense	19	19	1	
Income from Ongoing Operations before income taxes	43	39	4	
Income Tax Expense	9	6	(4)	
Net Income (loss) from ongoing operations	**34**	**34**	**1**	
Special Item - (Non Operating Income)	0	0	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 34	$ 34	$ 1	
KY Regulated Financing Costs	(3)	$ (3)	(0)	
KY Regulated Net Income	$ 31	$ 31	$ 1	
Earnings Per Share - Ongoing	$ 0.04	$ 0.04	$ 0.00	

Note: Schedules may not sum due to rounding.

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Arbough

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — March 2018

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 738	$ 719	$ 19	Due primarily to higher off-system sales revenue in January related to favorable weather and higher than budgeted YTD fuel recovery.
Gas Revenues	135	146	(11)	Due primarily to lower sales volumes as a result of unfavorable weather in February and lower than budgeted YTD gas cost recovery.
Total Revenues	873	865	8	
Cost of Sales:				
Fuel Electric Costs	216	199	(18)	Due primarily to increased fuel costs in January to source off-system sales and higher than budgeted YTD fuel prices.
Gas Supply Expenses	64	71	7	Due primarily to lower gas volumes as a result of unfavorable weather in February and lower than budgeted YTD gas prices.
Purchased Power	15	16	1	
Other Cost of Production	10	9	(0)	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	15	17	2	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	18	18	0	
Total Cost of Sales	338	330	(8)	
Gross Margin:				
Electric Margin	466	463	3	
Gas Margin	69	73	(4)	
Total Gross Margin	535	536	(1)	
O&M	181	187	7	Lower primarily due to lower storm and bad debt expense and timing of plant maintenance and other costs.
Depreciation & Amortization	100	101	1	
Taxes, Other than Income	17	17	0	
Other income (expense)	(1)	(4)	3	
EBIT	236	227	10	
Interest Expense	56	58	2	
Income from Ongoing Operations before income taxes	181	169	12	
Income Tax Expense	39	38	(1)	
Net Income (loss) from ongoing operations	**142**	**130**	**11**	
Special Item - (Non Operating Income)	0	0	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 142	$ 130	$ 11	
KY Regulated Financing Costs	(9)	(9)	(0)	
KY Regulated Net Income	133	$ 121	$ 11	
Earnings Per Share - Ongoing	$ 0.19	$ 0.17	$ 0.02	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E — March 2018

($ Millions)

	YTD Actual	YTD Budget	YTD Variance	Comments
Revenues:				
Electric Revenues	$ 285	$ 274	$ 11	Due primarily to higher off-system sales revenue in January related to favorable weather and higher than budgeted YTD fuel recovery.
Gas Revenues	135	146	(11)	Due primarily to lower sales volumes as a result of unfavorable weather in February and lower than budgeted YTD gas cost recovery.
Total Revenues	420	420	(0)	
Cost of Sales:				
Fuel Electric Costs	86	79	(7)	Due primarily to increased fuel costs in January to source off-system sales and higher than budgeted YTD fuel prices.
Gas Supply Expenses	64	71	7	Due primarily to lower gas volumes as a result of unfavorable weather in February and lower than budgeted YTD gas prices.
Purchased Power	11	12	0	
Other Cost of Production	4	4	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	6	7	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	8	8	0	
Total Cost of Sales	179	180	1	
Gross Margin:				
Electric Margin	172	167	5	See explanations above.
Gas Margin	69	73	(4)	
Total Gross Margin	241	240	1	
O&M	79	80	0	
Depreciation & Amortization	41	41	0	
Taxes, Other than Income	9	9	0	
Other income (expense)	(2)	(2)	1	
EBIT	111	108	3	
Interest Expense	18	19	1	
Income from Ongoing Operations before income taxes	92	89	4	
Income Tax Expense	21	21	(0)	
Net Income (loss) from ongoing operations	**$ 72**	**$ 68**	**$ 4**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Actual vs. Budget (YTD) - KU

March 2018

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 471	$ 463	$ 9	Due primarily to higher off-system sales revenue in January related to favorable weather and higher than budgeted YTD fuel recovery.
Gas Revenues	0	0	0	
Total Revenues	471	463	9	
Cost of Sales:				
Fuel Electric Costs	136	121	(15)	Due primarily to increased fuel costs in January to source off-system sales and higher than budgeted YTD fuel prices.
Gas Supply Expenses	0	0	0	
Purchased Power	17	20	4	
Other Cost of Production	6	5	(0)	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	9	10	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	10	10	0	
Total Cost of Sales	177	167	(10)	
Gross Margin:				
Electric Margin	294	296	(2)	
Gas Margin	0	0	0	
Total Gross Margin	294	296	(2)	
O&M	91	97	6	Lower primarily due to lower storm and bad debt expense and timing of plant maintenance and other costs.
Depreciation & Amortization	59	60	0	
Taxes, Other than Income	8	8	0	
Other income (expense)	0	(1)	2	
EBIT	136	130	6	
Interest Expense	25	25	1	
Income from Ongoing Operations before income taxes	112	105	7	
Income Tax Expense	24	24	(0)	
Net Income (loss) from ongoing operations	**$ 88**	**$ 81**	**$ 7**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

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Income Statement: Forecast vs. Budget - LKE Consolidated — March 2018

($ Millions)

	Full Year			
	Q1 Forecast	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,838	$ 2,840	$ (2)	
Gas Revenues	310	323	(13)	Due primarily to lower sales volumes as a result of unfavorable weather in February and lower than budgeted YTD gas cost recovery.
Total Revenues	3,148	3,163	(15)	
Cost of Sales:				
Fuel Electric Costs	780	762	(18)	Due primarily to increased fuel costs in January to source off-system sales and higher than budgeted YTD fuel prices.
Gas Supply Expenses	121	128	7	Due primarily to lower gas volumes as a result of unfavorable weather in February and lower than budgeted YTD gas prices.
Purchased Power	61	62	1	
Other Cost of Production	44	40	(4)	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	66	78	12	Due primarily to elimination of some DSM programs in the 2018 filing with the KPSC.
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	75	77	2	
Total Cost of Sales	1,147	1,146	(1)	
Gross Margin:				
Electric Margin	1,819	1,831	(12)	See explanations above.
Gas Margin	182	185	(3)	
Total Gross Margin	2,001	2,017	(16)	
O&M	752	752	0	
Depreciation & Amortization	406	410	4	
Taxes, Other than Income	67	67	0	
Other income (expense)	(6)	(10)	5	Due primarily to lower Pension non-service cost expense in the updated disclosures from Willis Towers Watson.
EBIT	771	778	(7)	
Interest Expense	238	241	3	
Income from Ongoing Operations before income taxes	533	537	(4)	
Income Tax Expense	113	117	4	
Net Income (loss) from ongoing operations	**420**	**420**	**$ (0)**	
Special Item - (Non Operating Income)	0	0	-	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 420	$ 420	$ (0)	
KY Regulated Financing Costs	(40)	(40)	(0)	
KY Regulated Net Income	$ 380	$ 380	$ (0)	
Earnings Per Share - Ongoing	$ 0.52	$ 0.52	$ (0.00)	

Note: Schedules may not sum due to rounding.

O&M								March 2018

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	21	22	1	(0)	(0)	(1)	1	2
Project Engineering	0	0	0	(0)	0	(0)	0	0
Transmission	3	3	0	(0)	0	(0)	(0)	0
Energy Supply and Analysis	1	1	(0)	0	0	0	0	(0)
Electric Distribution	6	6	(1)	(0)	(0)	(0)	0	(0)
Gas Distribution	3	3	(0)	0	(0)	(0)	(0)	(0)
Advanced Metering System	0	0	(0)	(0)	0	(0)	(0)	(0)
Safety and Technical Training	0	1	0	0	0	0	0	0
Environmental	1	1	0	0	0	0	0	0
Customer Services	8	8	0	(0)	(0)	(0)	0	0
SVP Operations Total	**44**	**45**	**1**	**(0)**	**(0)**	**(2)**	**1**	**2**
Audit Services	0	0	0	0	0	0	0	0
Controller	1	1	0	0	0	0	0	0
Supply Chain	0	0	0	0	(0)	0	(0)	0
Information Technology	4	5	1	0	(0)	0	0	0
Treasurer	2	2	0	(0)	0	0	0	0
State Regulation and Rates	1	0	(0)	0	0	0	(0)	(0)
Other	0	0	0	0	0	(0)	0	0
Chief Financial Officer Total	**8**	**9**	**1**	**0**	**(0)**	**0**	**(0)**	**0**
General Counsel	**2**	**2**	**(0)**	**0**	**0**	**(1)**	**0**	**0**
Human Resources	**1**	**1**	**0**	**0**	**0**	**(0)**	**0**	**0**
Corporate	**9**	**8**	**(1)**	**(1)**	**0**	**0**	**(0)**	**0**
Communication	**1**	**1**	**(0)**	**0**	**(0)**	**(0)**	**(0)**	**(0)**
Utility Total	**64**	**64**	**(0)**	**(0)**	**(0)**	**(2)**	**0**	**3**
Nonutility	**1**	**2**	**1**	**1**	**(0)**	**(0)**	**0**	**0**
O&M Total MTD	**65**	**66**	**1**	**0**	**(0)**	**(2)**	**0**	**3**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	48	51	3	(0)	1	(1)	(0)	4
Project Engineering	0	0	0	(0)	0	(0)	0	0
Transmission	8	9	1	(0)	1	(0)	(0)	(0)
Energy Supply and Analysis	4	4	0	0	0	0	0	(0)
Electric Distribution	17	17	(0)	(0)	1	(1)	0	(0)
Gas Distribution	10	9	(1)	0	(1)	(0)	(0)	(0)
Advanced Metering System	0	0	(0)	(0)	0	(0)	(0)	(0)
Safety and Technical Training	1	2	0	0	(0)	0	(0)	0
Environmental	2	2	0	(0)	0	0	0	0
Customer Services	24	25	2	(0)	0	0	0	1
SVP Operations Total	**113**	**118**	**5**	**(0)**	**3**	**(2)**	**(0)**	**5**
Audit Services	0	0	0	0	0	0	0	0
Controller	2	2	0	0	0	0	(0)	0
Supply Chain	1	1	0	0	(0)	(0)	(0)	0
Information Technology	13	15	2	1	(0)	0	0	0
Treasurer	6	6	0	(0)	0	0	0	0
State Regulation and Rates	1	1	(0)	0	0	0	(0)	0
Other	1	1	0	0	0	(0)	0	0
Chief Financial Officer Total	**25**	**26**	**2**	**1**	**(0)**	**(0)**	**(0)**	**1**
General Counsel	**5**	**4**	**(1)**	**0**	**0**	**(1)**	**0**	**0**
Human Resources	**2**	**2**	**0**	**0**	**0**	**(0)**	**0**	**0**
Corporate	**24**	**24**	**0**	**(0)**	**0**	**0**	**(0)**	**0**
Communication	**2**	**2**	**0**	**(0)**	**0**	**(0)**	**0**	**0**
Utility Total	**170**	**176**	**6**	**1**	**3**	**(3)**	**(0)**	**6**
Nonutility	**11**	**11**	**0**	**(1)**	**(0)**	**(0)**	**0**	**1**
O&M Total YTD	**181**	**187**	**7**	**0**	**3**	**(3)**	**(0)**	**7**

	Full Year							
	Forecast	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	215	216	1	(86)	(23)	(64)	(43)	217
Project Engineering	1	0	(0)	(0)	0	(0)	(0)	0
Transmission	38	38	0	(12)	(12)	(8)	(1)	33
Energy Supply and Analysis	13	13	(0)	(8)	0	(0)	(0)	8
Electric Distribution	74	75	0	(26)	(34)	(2)	(5)	68
Gas Distribution	42	39	(3)	(21)	(9)	(5)	(3)	34
Advanced Metering System	3	0	(3)	(0)	(2)	(1)	(0)	0
Safety and Technical Training	6	6	(0)	(4)	(0)	(1)	(0)	5
Environmental	7	8	1	(3)	0	(0)	(0)	4
Customer Services	98	97	(0)	(42)	(21)	(10)	(2)	75
SVP Operations Total	**497**	**492**	**(4)**	**(202)**	**(100)**	**(92)**	**(55)**	**445**
Audit Services	2	2	0	(2)	0	(0)	(0)	2
Controller	9	9	0	(7)	0	(2)	(0)	9
Supply Chain	4	4	(0)	(4)	(0)	(0)	(0)	4
Information Technology	58	58	(0)	(26)	(4)	(2)	(0)	32
Treasurer	23	23	1	(6)	0	(0)	(0)	6
State Regulation and Rates	5	5	(0)	(2)	0	(0)	(0)	2
Other	2	2	0	(0)	0	(1)	(0)	1
Chief Financial Officer Total	**103**	**103**	**0**	**(47)**	**(4)**	**(4)**	**(1)**	**56**
General Counsel	**18**	**18**	**0**	**(5)**	**0**	**(9)**	**(0)**	**14**
Human Resources	**7**	**7**	**(0)**	**(6)**	**0**	**(0)**	**(0)**	[illegible]
Corporate	**90**	**95**	**6**	**(83)**	**0**	**(1)**	**2**	**82**
Communication	**7**	**7**	**0**	**(3)**	**(0)**	**(1)**	**(3)**	[illegible]
Utility Total	**721**	**723**	**2**	**(345)**	**(104)**	**(108)**	**(57)**	**610**
Nonutility Total	**31**	**29**	**(2)**	**(11)**	9 **(0)**	**(1)**	**(0)**	**10**
O&M Total YTD	**752**	**752**	**(0)**	**(356)**	**(104)**	**(109)**	**(57)**	**620**

Note: Schedules may not sum due to rounding.

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Financing Activities — March 2018

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB						
Beg Bal	$ 890.0	$ 890.0	$ 0.0	$ 890.0	$ 890.0	$ 0.0
End Bal	890.0	890.0	0.0	890.0	890.0	0.0
Ave Bal	**$ 890.0**	**$ 890.0**	**$ 0.0**	**$ 890.0**	**$ 890.0**	**$ 0.0**
Interest Exp	**$ 3.6**	**$ 4.4**	**$ 0.7**	**$ 16.6**	**$ 18.3**	**$ 1.7**
Rate	**1.64%**	**1.97%**	**0.33%**	**1.84%**	**2.03%**	**0.19%**
FMB/Sr Nts/Loan with PPL						
Beg Bal	$ 4,310.0	$ 4,310.0	$ 0.0	$ 4,310.0	$ 4,310.0	$ 0.0
End Bal	4,410.0	4,424.0	14.0	4,735.1	4,643.2	(91.9)
Ave Bal	**$ 4,360.0**	**$ 4,367.0**	**$ 7.02**	**$ 4,522.6**	**$ 4,476.6**	**$ (45.96)**
Interest Exp	**$ 46.7**	**$ 47.0**	**$ 0.3**	**$ 192.7**	**$ 191.9**	**$ (0.7)**
Rate	**4.26%**	**4.29%**	**0.02%**	**4.21%**	**4.22%**	**0.01%**
Short-term Debt						
Beg Bal	$ 468.9	$ 468.9	$ 0.0	$ 468.9	$ 468.9	$ 0.0
End Bal	451.6	451.0	(0.7)	800.7	722.7	(78.1)
Ave Bal [1]	**$ 460.3**	**$ 459.9**	**$ (0.3)**	**$ 634.8**	**$ 595.8**	**$ (39.0)**
Interest Exp	**$ 2.7**	**$ 3.9**	**$ 1.2**	**$ 17.8**	**$ 19.5**	**$ 1.7**
Rate	**2.59%**	**3.59%**	**1.00%**	**2.86%**	**3.41%**	**0.56%**
Unamortized Debt Expense Bonds						
Beg Bal	$ (41.6)	$ (41.6)	$ 0.0	$ (41.6)	$ (41.6)	$ 0.0
End Bal	(40.9)	(40.9)	(0.0)	(38.2)	(38.3)	(0.0)
Ave Bal	**$ (41.3)**	**$ (41.3)**	**$ (0.0)**	**$ (39.9)**	**$ (39.9)**	**$ (0.0)**
Total End Bal	**$ 5,710.7**	**$ 5,724.0**	**$ 13.4**	**$ 6,387.6**	**$ 6,217.6**	**$ (170.0)**
Total Average Bal	**$ 5,657.9**	**$ 5,674.0**	**$ 16.2**	**$ 5,981.6**	**$ 5,901.9**	**$ (79.7)**
Total Expense Excl I/C [2]	**$ 55.7**	**$ 58.1**	**$ 2.3**	**$ 238.0**	**$ 240.8**	**$ 2.8**
Rate	**3.91%**	**4.06%**	**0.15%**	**3.90%**	**4.00%**	**0.10%**

[1] Short-term Debt YTD actual reflects average daily balances. All other average balances use an average monthly balance.
[2] Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed[3]	Letters of Credit Issued	Unused Capacity	Money Pool Loans
LKE	$ 375	$ 237		$ 138	
LG&E	700	337		363	$ 0
KU	598	78	$ 198	322	0
TOTAL	$ 1,673	$ 652	$ 198	$ 823	$ 0

[3] LG&E borrowed amount includes commercial paper issuances and $200M Term Loan. KU borrowed amount represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2018 Actual YTD	LKE 2018 Budget YTD	LG&E 2018 Actual YTD	LG&E 2018 Budget YTD	KU 2018 Actual YTD	KU 2018 Budget YTD
CFO pre-WC / Debt	17%	17%	26%	27%	26%	26%
CFO pre-WC + Interest / Interest	5.5	5.4	8.1	8.0	7.6	7.4
CFO pre-WC - Dividends / Debt	11%	11%	20%	20%	17%	16%
Debt to Capitalization	52%	52%	39%	38%	37%	37%

Credit Metrics Moody's	LKE 2018 BP 2019	LKE 2018 BP 2020	LG&E 2018 BP 2019	LG&E 2018 BP 2020	KU 2018 BP 2019	KU 2018 BP 2020
CFO pre-WC / Debt	14%	14%	19%	19%	19%	20%
CFO pre-WC + Interest / Interest	4.4	4.4	5.8	5.6	5.7	5.7
CFO pre-WC - Dividends / Debt	10%	10%	11%	10%	10%	11%
Debt to Capitalization	53%	52%	38%	38%	38%	38%

[1] Actuals represent a trailing 12 months.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2017	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — March 2018

($ Millions)

	3/31/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 27	$ 14	$ 13	Increase primarily due to timing of cash receipts at the utilities.
Accounts Receivable (Trade)	424	451	(27)	
Inventory	212	218	(6)	
Regulatory Assets Current	12	1	11	Primarily due to ECR regulatory asset reclassification to regulatory liability
Prepayments and other current assets	69	73	(4)	
Total Current Assets	745	758	(13)	
Property, Plant, and Equipment	12,135	12,183	(49)	
Intangible Assets	84	84	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	793	792	0	
Goodwill	997	997	0	
Other Long-term Assets	79	73	6	
Total Assets	**$ 14,834**	**$ 14,888**	**$ (55)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 301	$ 330	$ (29)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	59	58	1	
Derivative Liability	4	4	(0)	
Accrued Taxes	73	72	1	
Regulatory Liabilities Current	63	38	25	Primarily due to higher than budgeted DSM, and ECR regulatory asset reclassification.
Other Current Liabilities	257	294	(36)	Primarily due to ARO reclassification from current to non-current in actuals and decrease in credit cash adjustment for outstanding checks not yet funded versus the budget which assumed a static balance as of December 2017 when the budget was finalized.
Total Current Liabilities	758	797	(39)	
Debt - Affiliated Company	637	639	(2)	
Debt [(1)]	5,074	5,085	(11)	
Total Debt	5,711	5,724	(13)	
Deferred Tax Liabilities	882	884	(1)	
Investment Tax Credit	128	128	(0)	
Accum Provision for Pension & Related Benefits	265	257	8	
Asset Retirement Obligation	249	265	(15)	
Regulatory Liabilities Non Current	2,027	2,027	(0)	
Derivative Liability	18	21	(3)	
Other Liabilities	158	160	(2)	
Total Deferred Credits and Other Liabilities	3,728	3,741	(13)	
Equity	4,637	4,626	11	
Total Liabilities and Equity	**$ 14,834**	**$ 14,888**	**$ (55)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E — March 2018

($ Millions)

	3/31/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 14	$ 5	$ 9	
Accounts Receivable (Trade)	188	206	(18)	
Inventory	95	94	1	
Regulatory Assets Current	10	4	6	Primarily due to ECR regulatory asset reclassification to regulatory liability.
Prepayments and other current assets	56	50	6	
Total Current Assets	363	360	4	
Property, Plant, and Equipment	5,351	5,378	(27)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	406	408	(2)	
Goodwill	0	0	0	
Other Long-term Assets	26	13	12	Difference primarily due to reclassification of prepaid pension balance from Accumulated Provision for Pension & Related Benefits.
Total Assets	**$ 6,153**	**$ 6,165**	**$ (13)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 191	$ 197	$ (6)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	28	27	1	
Derivative Liability	4	4	(0)	
Accrued Taxes	24	24	(0)	
Regulatory Liabilities Current	29	18	12	Primarily due to higher than budgeted DSM, and ECR regulatory asset reclassification.
Other Current Liabilities	75	94	(19)	Primarily due to ARO reclassification from current to non-current in actuals and decrease in credit cash adjustment for outstanding checks not yet funded versus the budget which assumed a static balance as of December 2017 when the budget was finalized.
Total Current Liabilities	352	364	(12)	
Debt - Affiliated Company	0	0	0	
Debt [1]	1,945	1,933	12	
Total Debt	1,945	1,933	12	
Deferred Tax Liabilities	582	583	(1)	
Investment Tax Credit	35	35	(0)	
Accum Provision for Pension & Related Benefits	1	(12)	13	Difference due to reclassification of prepaid pension balance to other long term assets.
Asset Retirement Obligation	93	96	(4)	
Regulatory Liabilities Non Current	867	867	0	
Derivative Liability	18	21	(3)	
Other Liabilities	85	86	(1)	
Total Deferred Credits and Other Liabilities	1,680	1,675	4	
Equity	2,176	2,193	(17)	
Total Liabilities and Equity	**$ 6,153**	**$ 6,165**	**$ (13)**	

[1] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

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Balance Sheet - KU — March 2018

($ Millions)

	3/31/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 11	$ 5	$ 6	
Accounts Receivable (Trade)	235	244	(9)	
Inventory	117	124	(6)	
Regulatory Assets Current	2	(3)	5	Primarily due to ECR regulatory asset reclassification to regulatory liability.
Prepayments and other current assets	41	48	(6)	
Total Current Assets	407	418	(11)	
Property, Plant, and Equipment	6,775	6,797	(22)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	385	384	1	
Goodwill	0	0	0	
Other Long-term Assets	66	57	10	
Total Assets	**$ 7,646**	**$ 7,669**	**$ (23)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 163	$ 179	$ (15)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	31	31	0	
Derivative Liability	0	0	0	
Accrued Taxes	33	29	4	
Regulatory Liabilities Current	34	21	13	Primarily due to higher than budgeted DSM, and ECR regulatory asset reclassification.
Other Current Liabilities	139	139	(1)	
Total Current Liabilities	400	398	2	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,405	2,428	(23)	
Total Debt	2,405	2,428	(23)	
Deferred Tax Liabilities	696	700	(4)	
Investment Tax Credit	93	93	(0)	
Accum Provision for Pension & Related Benefits	0	(11)	11	Difference due to reclassification of prepaid pension balance to other long term assets.
Asset Retirement Obligation	157	168	(11)	
Regulatory Liabilities Non Current	1,094	1,095	(1)	
Derivative Liability	0	0	0	
Other Liabilities	43	42	0	
Total Deferred Credits and Other Liabilities	2,083	2,088	(5)	
Equity	2,758	2,755	3	
Total Liabilities and Equity	**$ 7,646**	**$ 7,669**	**$ (23)**	

(1) Includes all ST and LT debt.
Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

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KU and LG&E Combined
Reconciliation of Allowed Return to
12 months ended March 2018 Regulatory Return
and ROE from Ongoing Operations

Allowed Return [1]		9.76%	
Adjustments (net tax):			
Change in capitalization - non mechanism	0.28%		Growth in capitalization (rate base) between rate cases does not earn a return
Change in ROE from average mechanism rate base growth	0.00%		Mechanisms have a real-time return
Change in weighted cost of debt	0.04%		
Change in margins	0.06%		Higher revenue
Change in allowed expenses	0.47%		Lower expense
		0.86%	
Actual Regulated ROE		10.62%	

[1] Based on the most recent base rate filings with test years ending 6/30/18 KPSC, 12/31/16 FERC, 12/31/14 VA.
Note the allowed return is a blended rate of the previous authorized ROE of 10% after 7/1/16 and the current authorized ROE of 9.7% after 7/1/17

LG&E KU

PPL companies

Performance Report

April 2018

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Kentucky Regulated Dashboard — April 2018

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees[(1)]	4.93	2.29	1.92	1.33	1.30	0.97
Employee lost-time incidents	0	0	1	2	7	9
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,424	2,300	11,177	10,876	34,005	33,704
Utility EFOR	1.1%	5.0%	2.5%	5.0%	N/A	5.0%
Utility EAF	62.9%	67.0%	80.2%	78.4%	N/A	83.7%
Combined SAIFI	0.07	0.11	0.23	0.31	N/A	0.99
Combined SAIDI (minutes)	6.09	8.87	24.48	25.66	N/A	91.90
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	669	625	3,671	3,579	10,594	10,502
Commercial	555	564	2,485	2,439	7,861	7,815
Industrial	743	713	2,949	2,924	9,346	9,321
Municipals	125	128	573	589	1,763	1,778
Other	207	210	877	886	2,813	2,822
Off-System Sales	57	4	314	75	389	150
Total	2,356	2,244	10,870	10,494	32,766	32,389
Weather-Normalized Sales Growth			**TTM**			
Residential			1.20%			
Commercial			-0.46%			
Industrial			-1.89%			
Municipal			-4.61%			
Other			-2.47%			
Total			-0.75%			

	Current Month		YTD		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$131	$132	$597	$595	$1,819	$1,831
Gas Margins	$13	$13	$82	$86	$182	$185
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$102	$125	$353	$415	$1,231	$1,277
O&M ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
O&M – Management View[(2)]	$66	$70	$247	$257	$752	$752
O&M – GAAP View[(3)]	$73	$78	$278	$291	$861	$869
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,414	3,596	3,414	3,596	3,593	3,597
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	1	0	3	N/A	8
NERC Possible Violations[(4)]	1	0	4	3	N/A	8

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
Utility ROE[(5)]	10.5%	9.6%	9.6%
Average Utility Capitalization ($ millions)	$9,092	$9,571	$9,527

Variance Explanations

Lower YTD O&M primarily due timing of plant maintenance costs, lower materials, lower storm and vegetation management costs, bad debt expense and labor costs.

(1) Full year forecast amount shown represents target.

(2) Net of cost recovery mechanisms and variable costs of production.

(3) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses

(4) The possible violation issues for YTD Actual is believed to be minimal risk.

(5) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Major Developments

LKE filed direct testimony in the Tax Cuts and Jobs Act on April 6 and submitted data responses to requests from the KPSC and the Attorney General on April 20. No intervenor testimony was filed.

LG&E and KU continue their strong base of excellent customer service. Through three of four wave periods for the J.D. Power Electric Residential Study, KU and LG&E ranked first and fourth, respectively, among 15 utilities in the Midwest Midsize segment.

The spring outage season for power plant maintenance is nearing completion. Ten planned steam unit outages have taken place this year with $23 million in capital investment through April. No significant unexpected matters arose during inspections and the planned work.

KU earned national recognition as one of 43 utilities that have been designated a 2018 Environmental Champion by Market Strategies International.

LKE earned a Chartwell's 2018 Best Practices Award in Outage Communications. LKE won the Bronze Outage Communications Award for its transformation of the estimated restoration time process, improving efficiency and enabling a better customer service experience.

Significant Future Events

The formal hearing date for the Tax Cuts and Jobs Act will take place on May 24.

The formal hearing date for LKE's Advanced Metering Systems proceeding has been scheduled for July 24.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — April 2018

($ Millions)

	MTD Actual	MTD Budget	MTD Variance	Comments
Revenues:				
Electric Revenues	$ 206	$ 203	$ 2	
Gas Revenues	24	22	1	
Total Revenues	229	226	4	
Cost of Sales:				
Fuel Electric Costs	56	52	(4)	
Gas Supply Expenses	10	8	(2)	
Purchased Power	6	5	(0)	
Other Cost of Production	3	3	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	5	6	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	6	0	
Total Cost of Sales	85	80	(5)	
Gross Margin:				
Electric Margin	131	132	(1)	
Gas Margin	13	13	(0)	
Total Gross Margin	144	146	(2)	
O&M	66	70	4	
Depreciation & Amortization	34	34	0	
Taxes, Other than Income	6	6	(0)	
Other income (expense)	(3)	(1)	(2)	
EBIT	36	36	0	
Interest Expense	19	20	1	
Income from Ongoing Operations before income taxes	17	16	1	
Income Tax Expense	2	4	2	
Net Income (loss) from ongoing operations	**15**	**12**	**2**	
Special Item - (Non Operating Income)	(9)	0	(9)	Due to Kentucky state tax reform resulting in a reduction of the Kentucky Corporate income tax, a $9 million deferred tax expense was recorded related to the revaluing of non-utility deferred taxes.
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 5	$ 12	$ (7)	
KY Regulated Financing Costs	(3)	$ (3)	(0)	
KY Regulated Net Income	$ 2	$ 9	$ (7)	
Earnings Per Share - Ongoing	$ 0.02	$ 0.01	$ 0.00	

Note: Schedules may not sum due to rounding.

Case Nos. 2018-00294 and 2018-00295
Attachment to Filing Requirement
807 KAR 5:001 Sec. 16(7)(o)

Arbough

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — April 2018

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 944	$ 922	$ 21	Due primarily to higher off-system sales revenue in January related to favorable weather and higher than budgeted YTD fuel recovery.
Gas Revenues	158	168	(10)	Due primarily to lower sales volumes as a result of unfavorable weather in February and lower than budgeted YTD gas cost recovery.
Total Revenues	1,102	1,091	11	
Cost of Sales:				
Fuel Electric Costs	272	250	(22)	Due primarily to increased fuel costs in January to source off-system sales and higher than budgeted YTD fuel prices.
Gas Supply Expenses	75	80	5	Due primarily to lower gas volumes as a result of unfavorable weather in February and lower than budgeted YTD gas prices.
Purchased Power	21	21	0	
Other Cost of Production	12	12	(0)	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	19	22	3	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	24	24	1	
Total Cost of Sales	423	410	(13)	
Gross Margin:				
Electric Margin	597	595	2	
Gas Margin	82	86	(4)	
Total Gross Margin	679	681	(2)	
O&M	247	257	10	Lower primarily due to timing of plant maintenance costs, lower materials, lower storm and vegetation management costs, bad debt expense and labor costs.
Depreciation & Amortization	134	135	1	
Taxes, Other than Income	22	22	0	
Other income (expense)	(4)	(5)	0	
EBIT	272	262	10	
Interest Expense	75	78	3	
Income from Ongoing Operations before income taxes	197	185	13	
Income Tax Expense	41	42	1	
Net Income (loss) from ongoing operations	**156**	**143**	**14**	
Special Item - (Non Operating Income)	(9)	0	(9)	Due to Kentucky state tax reform resulting in a reduction of the Kentucky Corporate income tax, a $9 million deferred tax expense was recorded related to the revaluing of non-utility deferred taxes.
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 147	$ 143	$ 4	
KY Regulated Financing Costs	(12)	(12)	(0)	
KY Regulated Net Income	135	$ 131	$ 4	
Earnings Per Share - Ongoing	$ 0.21	$ 0.18	$ 0.03	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E

April 2018

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 367	$ 356	$ 12	Due primarily to higher off-system sales revenue in January related to favorable weather and higher than budgeted YTD fuel recovery.
Gas Revenues	158	168	(10)	Due primarily to lower sales volumes as a result of unfavorable weather in February and lower than budgeted YTD gas cost recovery.
Total Revenues	526	524	2	
Cost of Sales:				
Fuel Electric Costs	107	99	(9)	Due primarily to increased fuel costs in January to source off-system sales and higher than budgeted YTD fuel prices.
Gas Supply Expenses	75	80	5	Due primarily to lower gas volumes as a result of unfavorable weather in February and lower than budgeted YTD gas prices.
Purchased Power	15	16	0	
Other Cost of Production	5	5	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	7	9	2	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	11	11	0	
Total Cost of Sales	220	219	(1)	
Gross Margin:				
Electric Margin	224	219	5	See explanations above.
Gas Margin	82	86	(4)	
Total Gross Margin	306	305	1	
O&M	109	110	1	
Depreciation & Amortization	55	55	0	
Taxes, Other than Income	11	12	0	
Other income (expense)	(3)	(3)	(1)	
EBIT	127	126	2	
Interest Expense	25	26	1	
Income from Ongoing Operations before income taxes	103	100	3	
Income Tax Expense	22	23	1	
Net Income (loss) from ongoing operations	**$ 80**	**$ 76**	**$ 4**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Actual vs. Budget (YTD) - KU

April 2018

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 597	$ 587	$ 10	Due primarily to higher off-system sales revenue in January related to favorable weather and higher than budgeted YTD fuel recovery.
Gas Revenues	0	0	0	
Total Revenues	597	587	10	
Cost of Sales:				
Fuel Electric Costs	172	153	(19)	Due primarily to increased fuel costs in January to source off-system sales and higher than budgeted YTD fuel prices.
Gas Supply Expenses	0	0	0	
Purchased Power	20	24	4	
Other Cost of Production	7	7	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	12	13	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	13	13	0	
Total Cost of Sales	223	211	(13)	
Gross Margin:				
Electric Margin	374	376	(3)	
Gas Margin	0	0	0	
Total Gross Margin	374	376	(3)	
O&M	125	134	9	Lower primarily due to timing of plant maintenance costs, lower materials, lower storm and vegetation management costs, bad debt expense and labor costs.
Depreciation & Amortization	79	80	0	
Taxes, Other than Income	11	11	0	
Other income (expense)	(1)	(2)	1	
EBIT	158	150	8	
Interest Expense	33	34	1	
Income from Ongoing Operations before income taxes	125	117	8	
Income Tax Expense	26	27	0	
Net Income (loss) from ongoing operations	**$ 99**	**$ 90**	**$ 9**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

O&M								April 2018

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	24	26	2	(0)	(0)	8	2	(7)
Project Engineering	0	0	0	0	0	(0)	0	0
Transmission	3	4	1	(0)	0	0	0	0
Energy Supply and Analysis	1	1	0	(0)	0	0	0	0
Electric Distribution	6	6	(0)	(0)	0	(1)	0	(0)
Gas Distribution	3	3	(0)	(0)	(0)	0	0	(0)
Advanced Metering System	0	0	(0)	(0)	0	(0)	0	(0)
Safety and Technical Training	0	1	0	0	0	0	(0)	(0)
Environmental	1	1	0	(0)	0	0	(0)	0
Customer Services	8	8	(0)	(0)	(0)	0	0	(0)
SVP Operations Total	**46**	**49**	**2**	**(1)**	**0**	**8**	**2**	**(7)**
Audit Services	0	0	0	0	0	(0)	0	0
Controller	1	1	(0)	(0)	0	(0)	0	0
Supply Chain	0	0	0	(0)	(0)	(0)	0	0
Information Technology	5	4	(0)	0	(0)	(0)	0	(0)
Treasurer	2	2	(0)	(0)	0	(0)	0	(0)
State Regulation and Rates	0	0	0	0	0	0	(0)	(0)
Other	0	0	(0)	(0)	0	(0)	0	0
Chief Financial Officer Total	**9**	**8**	**(0)**	**(0)**	**(0)**	**(0)**	**0**	**0**
General Counsel	**1**	**1**	**0**	**0**	**0**	**(0)**	**0**	**0**
Human Resources	**1**	**1**	**(0)**	**(0)**	**0**	**(0)**	**0**	**0**
Corporate	**7**	**8**	**1**	**1**	**0**	**0**	**(0)**	**0**
Communication	**0**	**1**	**0**	**(0)**	**0**	**0**	**0**	**(0)**
Utility Total	**64**	**67**	**4**	**0**	**0**	**8**	**2**	**(7)**
Nonutility	**2**	**2**	**0**	**0**	**(0)**	**(0)**	**0**	**0**
O&M Total MTD	**66**	**70**	**4**	**1**	**0**	**8**	**2**	**(6)**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	72	77	6	(0)	1	7	1	(3)
Project Engineering	0	0	0	(0)	0	(0)	0	0
Transmission	11	13	2	(0)	2	(0)	(0)	(0)
Energy Supply and Analysis	5	5	0	0	0	0	0	(0)
Electric Distribution	23	23	(1)	(0)	2	(2)	0	(0)
Gas Distribution	13	12	(1)	0	(1)	(0)	(0)	(0)
Advanced Metering System	0	0	(0)	(0)	0	(0)	(0)	(0)
Safety and Technical Training	2	2	0	0	(0)	0	(0)	0
Environmental	2	3	0	(0)	0	0	0	0
Customer Services	32	33	1	(0)	(0)	0	0	1
SVP Operations Total	**160**	**167**	**7**	**(1)**	**3**	**6**	**1**	**(2)**
Audit Services	1	1	0	0	0	(0)	0	0
Controller	3	3	0	0	0	(0)	(0)	0
Supply Chain	1	1	0	0	(0)	(0)	(0)	0
Information Technology	18	19	1	1	(0)	0	0	0
Treasurer	8	8	0	(0)	0	(0)	0	0
State Regulation and Rates	2	2	(0)	0	0	0	(0)	(0)
Other	1	1	(0)	0	0	(0)	0	0
Chief Financial Officer Total	**33**	**35**	**1**	**1**	**(0)**	**(0)**	**(0)**	**1**
General Counsel	**6**	**5**	**(0)**	**0**	**0**	**(1)**	**0**	**1**
Human Resources	**2**	**2**	**0**	**0**	**0**	**(0)**	**0**	**0**
Corporate	**31**	**32**	**1**	**1**	**0**	**0**	**(0)**	**0**
Communication	**2**	**2**	**0**	**(0)**	**0**	**0**	**0**	**(0)**
Utility Total	**234**	**244**	**10**	**1**	**3**	**5**	**1**	**(0)**
Nonutility	**13**	**13**	**1**	**(0)**	**(0)**	**(0)**	**0**	**2**
O&M Total YTD	**247**	**257**	**10**	**1**	**3**	**4**	**1**	**1**

Note: Schedules may not sum due to rounding.

Financing Activities

April 2018

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance
PCB			
Beg Bal	$ 890.0	$ 890.0	$ 0.0
End Bal	890.0	890.0	0.0
Ave Bal	**$ 890.0**	**$ 890.0**	**$ 0.0**
Interest Exp	**$ 5.0**	**$ 5.9**	**$ 0.9**
Rate	**1.69%**	**1.98%**	**0.29%**
FMB/Sr Nts/Loan with PPL			
Beg Bal	$ 4,310.0	$ 4,310.0	$ 0.0
End Bal	4,410.0	4,424.0	14.0
Ave Bal	**$ 4,390.0**	**$ 4,395.6**	**$ 5.62**
Interest Exp	**$ 62.3**	**$ 62.8**	**$ 0.4**
Rate	**4.26%**	**4.29%**	**0.03%**
Short-term Debt			
Beg Bal	$ 468.9	$ 468.9	$ 0.0
End Bal	494.7	529.5	34.7
Ave Bal (1)	**$ 430.9**	**$ 455.3**	**$ 24.4**
Interest Exp	**$ 3.8**	**$ 5.4**	**$ 1.5**
Rate	**2.68%**	**3.54%**	**0.87%**
Unamortized Debt Expense Bonds			
Beg Bal	$ (41.6)	$ (41.6)	$ 0.0
End Bal	(40.6)	(40.6)	0.0
Ave Bal	**$ (41.1)**	**$ (41.1)**	**$ 0.0**
Total End Bal	**$ 5,754.1**	**$ 5,802.9**	**$ 48.8**
Total Average Bal	**$ 5,669.8**	**$ 5,699.8**	**$ 30.0**
Total Expense Excl I/C (2)	**$ 74.7**	**$ 77.6**	**$ 3.0**
Rate	**3.92%**	**4.06%**	**0.14%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use an average monthly balance.

(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(3)	Letters of Credit Issued	Unused Capacity	Money Pool Loans
LKE	$ 375	$ 262		$ 113	
LG&E	700	342		358	$ 0
KU	598	91	$ 198	309	0
TOTAL	$ 1,673	$ 695	$ 198	$ 780	$ 0

(3) LG&E borrowed amount includes commercial paper issuances and $200M Term Loan. KU borrowed amount represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2018 Actual YTD	LKE 2018 Budget YTD	LG&E 2018 Actual YTD	LG&E 2018 Budget YTD	KU 2018 Actual YTD	KU 2018 Budget YTD
CFO pre-WC / Debt	17%	17%	26%	26%	26%	25%
CFO pre-WC + Interest / Interest	5.4	5.4	8.1	8.0	7.5	7.4
CFO pre-WC - Dividends / Debt	11%	11%	19%	19%	16%	16%
Debt to Capitalization	52%	52%	39%	39%	37%	38%

Credit Metrics Moody's	LKE 2018 BP 2019	LKE 2018 BP 2020	LG&E 2018 BP 2019	LG&E 2018 BP 2020	KU 2018 BP 2019	KU 2018 BP 2020
CFO pre-WC / Debt	14%	14%	19%	19%	19%	20%
CFO pre-WC + Interest / Interest	4.4	4.4	5.8	5.6	5.7	5.7
CFO pre-WC - Dividends / Debt	10%	10%	11%	10%	10%	11%
Debt to Capitalization	53%	52%	38%	38%	38%	38%

[1] Actuals represent a trailing 12 months.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2017	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — April 2018

($ Millions)

	4/30/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 21	$ 14	$ 7	
Accounts Receivable (Trade)	383	417	(35)	
Inventory	225	225	0	
Regulatory Assets Current	11	11	1	
Prepayments and other current assets	81	81	0	
Total Current Assets	721	747	(27)	
Property, Plant, and Equipment	12,193	12,260	(67)	
Intangible Assets	83	83	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	795	791	4	
Goodwill	997	997	0	
Other Long-term Assets	80	74	6	
Total Assets	**$ 14,870**	**$ 14,953**	**$ (83)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 316	$ 329	$ (13)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	59	58	1	
Derivative Liability	4	4	(1)	
Accrued Taxes	44	52	(9)	
Regulatory Liabilities Current	63	48	15	Primarily due to higher than budgeted DSM, and ECR regulatory asset reclassification.
Other Current Liabilities	248	285	(37)	Primarily due to decrease in credit cash adjustment for outstanding checks not yet funded versus the budget which assumed a static balance as of December 2017 when the budget was finalized and settlement of WKE indemnification.
Total Current Liabilities	733	777	(44)	
Debt - Affiliated Company	662	648	14	
Debt [(1)]	5,092	5,155	(63)	
Total Debt	5,754	5,803	(49)	
Deferred Tax Liabilities	891	884	8	
Investment Tax Credit	128	128	(0)	
Accum Provision for Pension & Related Benefits	269	256	13	
Asset Retirement Obligation	252	260	(8)	
Regulatory Liabilities Non Current	2,025	2,025	(0)	
Derivative Liability	17	21	(4)	
Other Liabilities	158	160	(2)	
Total Deferred Credits and Other Liabilities	3,740	3,733	7	
Equity	4,642	4,640	3	
Total Liabilities and Equity	**$ 14,870**	**$ 14,953**	**$ (83)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

April 2018

($ Millions)

	4/30/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 8	$ 5	$ 3	
Accounts Receivable (Trade)	169	188	(19)	Due primarily to differences in actual vs. budget accounts receivable lag factors.
Inventory	99	95	3	
Regulatory Assets Current	10	10	1	
Prepayments and other current assets	59	51	7	
Total Current Assets	344	350	(5)	
Property, Plant, and Equipment	5,382	5,420	(38)	
Intangible Assets	6	6	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	404	406	(2)	
Goodwill	0	0	0	
Other Long-term Assets	25	14	11	Difference primarily due to reclassification of prepaid pension balance from Accumulated Provision for Pension & Related Benefits.
Total Assets	**$ 6,162**	**$ 6,196**	**$ (34)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 198	$ 195	$ 3	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	28	27	1	
Derivative Liability	4	4	(1)	
Accrued Taxes	20	18	3	
Regulatory Liabilities Current	28	21	7	
Other Current Liabilities	71	89	(18)	Primarily due to ARO reclassification from current to non-current in actuals, a decrease in credit cash adjustment for outstanding checks not yet funded and a decrease in customer advances versus the budget which assumed a static balance as of December 2017 when the budget was finalized. Decrease also due to lower accrued payroll balance versus budget.
Total Current Liabilities	349	354	(4)	
Debt - Affiliated Company	0	0	0	
Debt [1]	1,950	1,969	(19)	
Total Debt	1,950	1,969	(19)	
Deferred Tax Liabilities	582	583	(1)	
Investment Tax Credit	35	35	(0)	
Accum Provision for Pension & Related Benefits	1	(14)	14	Difference due to reclassification of prepaid pension balance to other long term assets.
Asset Retirement Obligation	92	95	(3)	
Regulatory Liabilities Non Current	866	866	(0)	
Derivative Liability	17	21	(4)	
Other Liabilities	85	86	(0)	
Total Deferred Credits and Other Liabilities	1,677	1,672	5	
Equity	2,185	2,201	(16)	
Total Liabilities and Equity	**$ 6,162**	**$ 6,196**	**$ (34)**	

[1] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

Balance Sheet - KU April 2018

($ Millions)

	4/30/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 12	$ 5	$ 7	
Accounts Receivable (Trade)	213	228	(15)	
Inventory	126	129	(3)	
Regulatory Assets Current	1	1	0	
Prepayments and other current assets	49	52	(3)	
Total Current Assets	402	416	(14)	
Property, Plant, and Equipment	6,802	6,832	(30)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	389	384	5	
Goodwill	0	0	0	
Other Long-term Assets	67	57	9	
Total Assets	**$ 7,673**	**$ 7,702**	**$ (30)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 179	$ 182	$ (3)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	31	31	0	
Derivative Liability	0	0	0	
Accrued Taxes	22	16	6	
Regulatory Liabilities Current	34	27	8	
Other Current Liabilities	135	138	(2)	
Total Current Liabilities	401	392	8	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,418	2,462	(44)	
Total Debt	2,418	2,462	(44)	
Deferred Tax Liabilities	696	700	(4)	
Investment Tax Credit	93	93	(0)	
Accum Provision for Pension & Related Benefits	0	(12)	12	Difference due to reclassification of prepaid pension balance to other long term assets.
Asset Retirement Obligation	160	165	(5)	
Regulatory Liabilities Non Current	1,094	1,094	(0)	
Derivative Liability	0	0	0	
Other Liabilities	42	43	(0)	
Total Deferred Credits and Other Liabilities	2,085	2,083	1	
Equity	2,769	2,764	5	
Total Liabilities and Equity	**$ 7,673**	**$ 7,702**	**$ (30)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

PPL companies

Performance Report

May 2018

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Kentucky Regulated Dashboard

May 2018

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees[(1)]	1.10	1.09	1.55	1.28	1.30	0.97
Employee lost-time incidents	0	0	1	2	6	9
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,905	2,653	14,082	13,530	34,257	33,704
Utility EFOR	2.9%	5.0%	2.6%	5.0%	N/A	5.0%
Utility EAF	83.6%	88.1%	80.9%	80.4%	N/A	83.7%
Combined SAIFI	0.08	0.09	0.31	0.39	N/A	0.99
Combined SAIDI (minutes)	7.93	8.22	32.43	33.87	N/A	91.90
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	905	700	4,577	4,279	10,785	10,502
Commercial	710	648	3,196	3,087	7,928	7,815
Industrial	799	817	3,749	3,741	9,274	9,321
Municipals	150	136	724	725	1,836	1,778
Other	244	239	1,121	1,125	2,823	2,822
Off-System Sales	40	19	354	94	410	150
Total	2,849	2,558	13,719	13,052	33,055	32,389
Weather-Normalized Sales Growth			**TTM**			
Residential			0.75%			
Commercial			-0.47%			
Industrial			-2.09%			
Municipal			-4.67%			
Other			-2.38%			
Total			-0.95%			

	Current Month		YTD		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$155	$142	$752	$738	$1,824	$1,831
Gas Margins	$10	$11	$92	$97	$181	$185
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$91	$118	$444	$533	$1,222	$1,277
O&M ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
O&M – Management View[(2)]	$59	$63	$306	$320	$752	$752
O&M – GAAP View[(3)]	$67	$72	$345	$363	$858	$869
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,438	3,597	3,438	3,597	3,598	3,597
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	0	3	N/A	8
NERC Possible Violations[(4)]	0	1	4	4	N/A	8

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
Utility ROE[(5)]	10.6%	9.6%	9.6%
Average Utility Capitalization ($ millions)	$9,127	$9,571	$9,527

Major Developments

The formal hearing was held in the Tax Cuts and Jobs Act case based on the Company's petition for reconsideration. LKE is responding to post-hearing data requests and briefs will then be filed no later than June 29. We expect an Order from the Commission after the July 4 holiday.

SERC delivered the exit presentation regarding the audit of the Critical Infrastructure Protection ("CIP") and Operations & Planning ("O&P") reliability standards. The results of the audit were excellent with no violations or areas of concern related to the CIP standards, while finding only one minor potential violation and one minor area of concern related to the O&P standards. The audit staff was complimentary of LKE's workforce and the Company as a whole, and mentioned that they viewed LKE as one of its top performing entities.

[redacted] has signed a contract for the purchase of a 1,000 share subscription to the Solar Share program. This brings the total subscriptions to 1,943 shares, pushing the Company closer to the 2,000 share level required to begin construction of the first 500-kilowatt section of the initiative. In addition, the inaugural Business Solar project for the Archdiocese of Louisville was unveiled recently at a press conference. The Archbishop Joseph E. Kurtz and several Company representatives celebrated the launch of a 33.6 kW on-site roof mounted solar array that LKE will own, operate, and maintain.

The Virginia State Corporation Commission issued an Order approving the settlement in the Virginia rate case. The new rates became effective June 1, 2018.

LKE was recognized at the annual Worksite Wellness Conference hosted by the Worksite Wellness Council of Louisville. For the third year in a row, the Company received a Platinum Award for its programs and initiatives supporting wellness. The award qualifies the Company for the national competition which focuses on the 100 Healthiest Employer Award.

For the second consecutive year, the Company received the ESGR (Employer Support of the Guard and Reserve) Pro Patria Award — the United States Defense Department's highest state-level award for providing support to employees serving in the Kentucky National Guard and Reserve. This follows earlier national recognition from being named a finalist for the 2018 Secretary of Defense Employer Support Freedom Award.

A storm event which began on May 31 and continued through June 2, ranked as the 11th largest storm in Company history since we began tracking them in the current manner. The event resulted in 82K customers affected, 766 downed wires, and 33 broken poles. The Company restored 95 percent of customers within 24 hours.

Variance Explanations

Higher margins MTD primarily due to higher sales volumes from favorable weather, resulting in higher retail electric base energy revenue of $13 million.

Higher margins YTD primarily due to higher sales volumes from favorable weather, resulting in higher retail electric base energy revenue of $19 million partially offset by lower demand revenue of $3 million, lower gas margins of $5 million and other margin components of $3 million.

Lower O&M YTD primarily due timing of plant maintenance costs ($2 million), lower materials ($3 million), lower storm and vegatation management costs ($2 million), labor costs ($3 million) and bad debt expense.

Significant Future Events

The formal hearing date for LKE's Advanced Metering Systems proceeding will occur on July 24.

(1) Full year forecast amount shown represents target.

(2) Net of cost recovery mechanisms and variable costs of production.

(3) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses

(4) The possible violation issues for YTD Actual is believed to be minimal risk.

(5) Excludes goodwill and other purchase accounting adjustments.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — May 2018

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 240	$ 219	$ 21	Due primarily to higher sales volumes from favorable weather.
Gas Revenues	14	16	(2)	
Total Revenues	254	235	18	
Cost of Sales:				
Fuel Electric Costs	66	58	(8)	Due primarily to higher fuel costs related to higher sales volumes from favorable weather.
Gas Supply Expenses	4	5	1	
Purchased Power	5	5	(0)	
Other Cost of Production	3	3	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	5	5	0	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	6	0	
Total Cost of Sales	89	82	(6)	
Gross Margin:				
Electric Margin	155	142	13	See explanations above.
Gas Margin	10	11	(1)	
Total Gross Margin	165	153	12	
O&M	59	63	4	
Depreciation & Amortization	34	34	0	
Taxes, Other than Income	5	6	0	
Other income (expense)	(0)	(1)	1	
EBIT	67	50	17	
Interest Expense	19	20	1	
Income from Ongoing Operations before income taxes	47	30	18	
Income Tax Expense	9	7	(2)	
Net Income (loss) from ongoing operations	**39**	**22**	**16**	
Special Item - (Non Operating Income)	0	0	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 39	$ 22	$ 16	
KY Regulated Financing Costs	(3)	$ (3)	(0)	
KY Regulated Net Income	$ 36	$ 19	$ 16	
Earnings Per Share - Ongoing	$ 0.05	$ 0.03	$ 0.02	

Note: Schedules may not sum due to rounding.

Case Nos. 2018-00294 and 2018-00295
Attachment to Filing Requirement
807 KAR 5:001 Sec. 16(7)(o)

Arbough

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — May 2018

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,183	$ 1,142	$ 42	Due primarily to higher sales volumes from favorable weather.
Gas Revenues	172	185	(12)	Due primarily to lower sales volumes as a result of unfavorable weather in February and lower than budgeted YTD gas cost recovery.
Total Revenues	1,356	1,326	30	
Cost of Sales:				
Fuel Electric Costs	338	309	(30)	Due primarily to higher fuel costs related to higher sales volumes from favorable weather.
Gas Supply Expenses	78	84	6	Due primarily to lower gas volumes as a result of unfavorable weather in February and lower than budgeted YTD gas prices.
Purchased Power	26	26	(0)	
Other Cost of Production	15	15	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	24	28	3	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	30	30	1	
Total Cost of Sales	511	492	(20)	
Gross Margin:				
Electric Margin	752	738	15	See explanations above.
Gas Margin	92	97	(5)	See explanations above.
Total Gross Margin	844	834	10	
O&M	306	320	14	Lower primarily due to timing of plant maintenance costs, lower materials, lower storm and vegetation management costs, labor costs and bad debt expense.
Depreciation & Amortization	168	169	1	
Taxes, Other than Income	27	28	1	
Other income (expense)	(4)	(5)	1	
EBIT	339	312	27	
Interest Expense	94	98	4	
Income from Ongoing Operations before income taxes	245	214	30	
Income Tax Expense	50	49	(1)	
Net Income (loss) from ongoing operations	**195**	**165**	**30**	
Special Item - (Non Operating Income)	(9)	0	(9)	Due to Kentucky state tax reform resulting in a reduction of the Kentucky Corporate income tax, a $9 million deferred tax expense was recorded related to the revaluing of non-utility deferred taxes.
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 186	$ 165	$ 21	
KY Regulated Financing Costs	(15)	(15)	(0)	
KY Regulated Net Income	171	$ 150	$ 21	
Earnings Per Share - Ongoing	$ 0.26	$ 0.21	$ 0.05	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E

May 2018

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 466	$ 446	$ 20	Due primarily to higher sales volumes from favorable weather.
Gas Revenues	172	185	(12)	Due primarily to lower sales volumes as a result of unfavorable weather in February and lower than budgeted YTD gas cost recovery.
Total Revenues	639	631	8	
Cost of Sales:				
Fuel Electric Costs	133	122	(11)	Due primarily to higher fuel costs related to higher sales volumes from favorable weather.
Gas Supply Expenses	78	84	6	Due primarily to lower gas volumes as a result of unfavorable weather in February and lower than budgeted YTD gas prices.
Purchased Power	20	20	0	
Other Cost of Production	6	7	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	9	11	2	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	13	14	0	
Total Cost of Sales	259	257	(2)	
Gross Margin:				
Electric Margin	287	277	10	See explanations above.
Gas Margin	92	97	(5)	See explanations above.
Total Gross Margin	379	374	6	
O&M	136	138	3	
Depreciation & Amortization	68	69	1	
Taxes, Other than Income	14	15	0	
Other income (expense)	(4)	(3)	(1)	
EBIT	158	149	9	
Interest Expense	31	33	2	
Income from Ongoing Operations before income taxes	127	116	11	
Income Tax Expense	28	28	(0)	
Net Income (loss) from ongoing operations	**$ 99**	**$ 88**	**$ 10**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Actual vs. Budget (YTD) - KU — May 2018

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 740	$ 718	$ 22	Due primarily to higher sales volumes from favorable weather.
Gas Revenues	0	0	0	
Total Revenues	740	718	22	
Cost of Sales:				
Fuel Electric Costs	212	188	(24)	Due primarily to higher fuel costs related to higher sales volumes from favorable weather.
Gas Supply Expenses	0	0	0	
Purchased Power	23	27	5	Due primarily to lower than anticipated intercompany expense for native load fuel.
Other Cost of Production	8	9	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	15	17	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	16	17	0	
Total Cost of Sales	275	258	(17)	
Gross Margin:				
Electric Margin	465	461	4	
Gas Margin	0	0	0	
Total Gross Margin	465	461	4	
O&M	156	166	11	Lower primarily due to timing of plant maintenance costs, lower storm and vegetation management costs, labor costs and bad debt expense.
Depreciation & Amortization	99	100	1	
Taxes, Other than Income	13	13	0	
Other income (expense)	(1)	(2)	1	
EBIT	196	179	17	
Interest Expense	41	42	1	
Income from Ongoing Operations before income taxes	155	137	18	
Income Tax Expense	34	32	(2)	
Net Income (loss) from ongoing operations	**$ 121**	**$ 105**	**$ 16**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

O&M — May 2018

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	16	17	1	0	0	2	0	(1)
Project Engineering	0	0	0	0	0	(0)	0	0
Transmission	3	3	0	(0)	0	0	(0)	0
Energy Supply and Analysis	1	1	0	0	0	0	0	(0)
Electric Distribution	6	6	1	0	1	(1)	0	0
Gas Distribution	4	4	0	0	(0)	1	0	(0)
Advanced Metering System	0	0	(0)	0	0	(0)	0	(0)
Safety and Technical Training	0	1	0	0	0	0	(0)	0
Environmental	1	1	0	0	0	0	0	0
Customer Services	7	8	0	0	(0)	0	0	0
Chief Operating Officer Total	**38**	**41**	**3**	**1**	**1**	**2**	**0**	**(1)**
Audit Services	0	0	0	0	0	0	0	0
Controller	1	1	0	0	0	0	(0)	0
Supply Chain	0	0	0	0	(0)	(0)	(0)	(0)
Information Technology	5	5	0	1	(0)	(0)	0	0
Treasurer	2	2	0	(0)	0	0	0	0
State Regulation and Rates	0	0	0	0	0	(0)	(0)	0
Other	0	0	(0)	0	0	(0)	0	0
Chief Financial Officer Total	**9**	**9**	**0**	**1**	**(0)**	**(0)**	**0**	**0**
General Counsel	**2**	**2**	**(0)**	**0**	**0**	**(0)**	**0**	**0**
Human Resources	**1**	**1**	**0**	**0**	**(0)**	**0**	**(0)**	**0**
Corporate	**8**	**8**	**(0)**	**0**	**0**	**(0)**	**(0)**	**(0)**
Communication	**1**	**1**	**0**	**0**	**(0)**	**(0)**	**0**	**0**
Utility Total	**58**	**61**	**3**	**2**	**1**	**1**	**0**	**(0)**
Nonutility	**2**	**2**	**0**	**0**	**(0)**	**(0)**	**0**	**0**
O&M Total MTD	**59**	**63**	**4**	**2**	**1**	**1**	**0**	**(0)**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	88	95	7	0	1	9	2	(4)
Project Engineering	0	0	0	(0)	0	(0)	0	0
Transmission	14	16	2	(0)	2	(0)	(0)	(0)
Energy Supply and Analysis	6	6	0	0	0	0	0	(0)
Electric Distribution	29	29	(0)	(0)	3	(3)	0	(0)
Gas Distribution	17	16	(1)	0	(1)	1	(0)	(0)
Advanced Metering System	1	0	(0)	0	0	(0)	(0)	(0)
Safety and Technical Training	2	3	0	0	(0)	0	(0)	0
Environmental	3	3	1	(0)	0	0	0	0
Customer Services	39	41	2	(0)	(0)	1	0	1
Chief Operating Officer Total	**198**	**209**	**10**	**0**	**4**	**8**	**2**	**(3)**
Audit Services	1	1	0	0	0	(0)	0	0
Controller	4	4	0	0	0	(0)	(0)	0
Supply Chain	2	2	0	0	(0)	(0)	(0)	0
Information Technology	23	25	2	2	(0)	0	0	0
Treasurer	10	10	0	(0)	0	(0)	0	0
State Regulation and Rates	2	2	(0)	0	0	0	(0)	(0)
Other	1	1	(0)	0	0	(1)	0	0
Chief Financial Officer Total	**42**	**44**	**2**	**2**	**(0)**	**(0)**	**(0)**	**1**
General Counsel	**7**	**7**	**(0)**	**0**	**0**	**(2)**	**0**	**1**
Human Resources	**3**	**3**	**0**	**0**	**(0)**	**(0)**	**0**	**0**
Corporate	**39**	**40**	**1**	**1**	**0**	**0**	**(0)**	**0**
Communication	**3**	**3**	**0**	**0**	**0**	**(0)**	**0**	**0**
Utility Total	**291**	**305**	**13**	**3**	**4**	**6**	**2**	**(1)**
Nonutility	**15**	**15**	**1**	**(0)**	**(0)**	**(1)**	**0**	**2**
O&M Total YTD	**306**	**320**	**14**	**3**	**4**	**5**	**2**	**1**

Note: Schedules may not sum due to rounding.

Financing Activities — May 2018

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance
PCB			
Beg Bal	$ 890.0	$ 890.0	$ 0.0
End Bal	890.0	890.0	0.0
Ave Bal	**$ 890.0**	**$ 890.0**	**$ 0.0**
Interest Exp	**$ 6.4**	**$ 7.4**	**$ 1.0**
Rate	**1.72%**	**1.99%**	**0.27%**
FMB/Sr Nts/Loan with PPL			
Beg Bal	$ 4,310.0	$ 4,310.0	$ 0.0
End Bal	4,660.0	4,424.0	(236.0)
Ave Bal	**$ 4,435.0**	**$ 4,400.4**	**$ (34.64)**
Interest Exp	**$ 78.8**	**$ 78.6**	**$ (0.3)**
Rate	**4.24%**	**4.26%**	**0.02%**
Short-term Debt			
Beg Bal	$ 468.9	$ 468.9	$ 0.0
End Bal	280.6	605.7	325.1
Ave Bal (1)	**$ 404.1**	**$ 480.3**	**$ 76.2**
Interest Exp	**$ 4.4**	**$ 7.0**	**$ 2.6**
Rate	**2.62%**	**3.49%**	**0.87%**
Unamortized Debt Expense Bonds			
Beg Bal	$ (41.6)	$ (41.6)	$ 0.0
End Bal	(40.5)	(41.0)	(0.5)
Ave Bal	**$ (41.0)**	**$ (41.1)**	**$ (0.1)**
Total End Bal	**$ 5,790.1**	**$ 5,878.7**	**$ 88.6**
Total Average Bal	**$ 5,688.1**	**$ 5,729.6**	**$ 41.5**
Total Expense Excl I/C (2)	**$ 94.0**	**$ 97.6**	**$ 3.5**
Rate	**3.91%**	**4.03%**	**0.12%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use an average monthly balance.

(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(3)	Letters of Credit Issued	Unused Capacity	Money Pool Loans
LKE	$ 375	$ 11		$ 364	
LG&E	700	360		340	$ 0
KU	598	109	$ 198	291	0
TOTAL	$ 1,673	$ 481	$ 198	$ 994	$ 0

(3) LG&E borrowed amount includes commercial paper issuances and $200M Term Loan. KU borrowed amount represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2018 Actual YTD	LKE 2018 Budget YTD	LG&E 2018 Actual YTD	LG&E 2018 Budget YTD	KU 2018 Actual YTD	KU 2018 Budget YTD
CFO pre-WC / Debt	17%	17%	26%	26%	26%	25%
CFO pre-WC + Interest / Interest	5.5	5.3	8.1	7.9	7.5	7.3
CFO pre-WC - Dividends / Debt	11%	11%	20%	19%	16%	16%
Debt to Capitalization	52%	52%	39%	39%	37%	38%

Credit Metrics Moody's	LKE 2018 BP 2019	LKE 2018 BP 2020	LG&E 2018 BP 2019	LG&E 2018 BP 2020	KU 2018 BP 2019	KU 2018 BP 2020
CFO pre-WC / Debt	14%	14%	19%	19%	19%	20%
CFO pre-WC + Interest / Interest	4.4	4.4	5.8	5.6	5.7	5.7
CFO pre-WC - Dividends / Debt	10%	10%	11%	10%	10%	11%
Debt to Capitalization	53%	52%	38%	38%	38%	38%

[1] Actuals represent a trailing 12 months.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2017	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — May 2018

($ Millions)

	5/31/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 14	$ 14	$ 0	
Accounts Receivable (Trade)	382	427	(45)	Due primarily to differences in actual vs. budget accounts receivable lag factors.
Inventory	231	225	6	
Regulatory Assets Current	10	10	(0)	
Prepayments and other current assets	83	78	6	
Total Current Assets	721	754	(33)	
Property, Plant, and Equipment	12,239	12,327	(88)	
Intangible Assets	83	83	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	797	790	7	
Goodwill	997	997	0	
Other Long-term Assets	81	74	6	
Total Assets	**$ 14,918**	**$ 15,026**	**$ (108)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 306	$ 326	$ (19)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	59	58	1	
Derivative Liability	4	4	(0)	
Accrued Taxes	61	65	(5)	
Regulatory Liabilities Current	67	60	7	
Other Current Liabilities	214	247	(32)	Primarily due to decrease in credit cash adjustment for outstanding checks not yet funded versus the budget which assumed a static balance as of December 2017 when the budget was finalized and settlement of WKE indemnification.
Total Current Liabilities	711	760	(48)	
Debt - Affiliated Company	661	656	5	
Debt [(1)]	5,129	5,222	(93)	
Total Debt	5,790	5,879	(89)	
Deferred Tax Liabilities	889	884	5	
Investment Tax Credit	128	128	(0)	
Accum Provision for Pension & Related Benefits	270	254	16	
Asset Retirement Obligation	250	254	(4)	
Regulatory Liabilities Non Current	2,025	2,023	2	
Derivative Liability	17	20	(3)	
Other Liabilities	157	161	(3)	
Total Deferred Credits and Other Liabilities	3,736	3,724	12	
Equity	4,681	4,663	18	
Total Liabilities and Equity	**$ 14,918**	**$ 15,026**	**$ (108)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

May 2018

($ Millions)

	5/31/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 6	$ 5	$ 1	
Accounts Receivable (Trade)	167	192	(25)	Due primarily to differences in actual vs. budget accounts receivable lag factors.
Inventory	102	94	7	
Regulatory Assets Current	10	10	0	
Prepayments and other current assets	48	50	(2)	
Total Current Assets	332	350	(18)	
Property, Plant, and Equipment	5,405	5,456	(51)	
Intangible Assets	6	6	0	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	405	405	(0)	
Goodwill	0	0	0	
Other Long-term Assets	25	14	11	Difference primarily due to reclassification of prepaid pension balance from Accumulated Provision for Pension & Related Benefits.
Total Assets	**$ 6,173**	**$ 6,231**	**$ (58)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 170	$ 191	$ (20)	Primarily due to lower capital expenditures.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	28	27	1	
Derivative Liability	4	4	(0)	
Accrued Taxes	29	25	4	
Regulatory Liabilities Current	31	26	5	
Other Current Liabilities	62	80	(18)	Primarily due to ARO reclassification from current to non-current in actuals, a decrease in credit cash adjustment for outstanding checks not yet funded and a decrease in customer advances versus the budget which assumed a static balance as of December 2017 when the budget was finalized.
Total Current Liabilities	325	353	(29)	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	1,968	1,997	(29)	
Total Debt	1,968	1,997	(29)	
Deferred Tax Liabilities	582	583	(1)	
Investment Tax Credit	35	35	(0)	
Accum Provision for Pension & Related Benefits	1	(15)	15	Difference due to reclassification of prepaid pension balance to other long term assets.
Asset Retirement Obligation	91	93	(2)	
Regulatory Liabilities Non Current	866	865	1	
Derivative Liability	17	20	(3)	
Other Liabilities	86	86	(0)	
Total Deferred Credits and Other Liabilities	1,677	1,668	9	
Equity	2,203	2,214	(10)	
Total Liabilities and Equity	**$ 6,173**	**$ 6,231**	**$ (58)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

Balance Sheet - KU May 2018

($ Millions)

	5/31/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 8	$ 5	$ 3	
Accounts Receivable (Trade)	215	235	(20)	
Inventory	130	131	(1)	
Regulatory Assets Current	0	0	(0)	
Prepayments and other current assets	51	51	(0)	
Total Current Assets	403	422	(19)	
Property, Plant, and Equipment	6,826	6,863	(37)	
Intangible Assets	13	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	390	384	6	
Goodwill	0	0	0	
Other Long-term Assets	67	58	9	
Total Assets	**$ 7,699**	**$ 7,740**	**$ (41)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 176	$ 181	$ (5)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	31	31	0	
Derivative Liability	0	0	0	
Accrued Taxes	32	23	8	
Regulatory Liabilities Current	36	34	2	
Other Current Liabilities	113	112	1	
Total Current Liabilities	387	381	6	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,437	2,501	(65)	
Total Debt	2,437	2,501	(65)	
Deferred Tax Liabilities	696	700	(4)	
Investment Tax Credit	93	93	(0)	
Accum Provision for Pension & Related Benefits	0	(12)	12	Difference due to reclassification of prepaid pension balance to other long term assets.
Asset Retirement Obligation	158	161	(2)	
Regulatory Liabilities Non Current	1,094	1,094	1	
Derivative Liability	0	0	0	
Other Liabilities	42	43	(1)	
Total Deferred Credits and Other Liabilities	2,083	2,078	6	
Equity	2,792	2,779	12	
Total Liabilities and Equity	**$ 7,699**	**$ 7,740**	**$ (41)**	

[(1)] Includes all ST and LT debt.
Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

PPL companies

Performance Report

June 2018

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Kentucky Regulated Dashboard — June 2018

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees[1]	1.01	0.34	1.46	1.00	1.30	0.97
Employee lost-time incidents	1	2	2	4	7	9
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,046	3,026	17,129	16,556	34,278	33,704
Utility EFOR	1.2%	5.0%	2.3%	5.0%	N/A	5.0%
Utility EAF	91.6%	92.9%	82.7%	82.4%	N/A	83.7%
Combined SAIFI	0.12	0.13	0.44	0.52	N/A	0.99
Combined SAIDI (minutes)	13.56	12.80	45.99	46.67	N/A	91.90
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	968	892	5,544	5,171	10,863	10,502
Commercial	740	727	3,936	3,814	8,004	7,815
Industrial	782	858	4,530	4,599	9,176	9,321
Municipals	162	150	885	876	1,834	1,778
Other	249	260	1,370	1,385	2,787	2,822
Off-System Sales	25	4	379	98	614	150
Total	2,925	2,892	16,644	15,943	33,278	32,389
Weather-Normalized Sales Growth			**TTM**			
Residential			0.23%			
Commercial			-0.58%			
Industrial			-1.43%			
Municipal			-4.44%			
Other			-1.62%			
Total			-0.87%			

	Current Month		YTD		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$162	$159	$914	$897	$1,827	$1,831
Gas Margins	$10	$10	$102	$106	$181	$185
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$82	$104	$526	$638	$1,235	$1,277
O&M ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
O&M – Management View[2]	$62	$60	$368	$380	$752	$752
O&M – GAAP View[3]	$71	$70	$416	$433	$855	$869
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,439	3,597	3,439	3,597	3,598	3,597
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	0	3	N/A	8
NERC Possible Violations[4]	3	0	7	4	N/A	8

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
Utility ROE[5]	10.7%	9.9%	9.6%
Average Utility Capitalization ($ millions)	$9,171	$9,497	$9,527

Major Developments

The Company continues to build on its outstanding customer satisfaction performance as it won another J.D. Power award. KU ranked first (with a score of 755) among the mid-sized utilities in the Midwest region of the 2018 Electric Utility Residential Customer Satisfaction study. LG&E, however, slid from 2nd to 7th based upon colder weather causing higher bills (gas heat) this winter. We are evaluating why such a large slide.

Business First, the weekly business journal for Greater Louisville, announced LG&E and KU as the winner of the Healthiest Employer Award among businesses with 1,500-4,999 employees. The Company last won the award in 2016 and was named a finalist in 2017.

LKE has reached the 2,000 share level required to begin construction of the first 500-kilowatt section of its Solar Share (Community Solar) program. The Company has closed on the site for the program and is targeting to have the system in operation by the first quarter of 2019.

The Company continues its outstanding safety performance as a number of locations have achieved recent milestones:
- Electric Distribution employees at the Elizabethtown Operations Center recently won the Edison Electric Institute Safety Achievement Award for completing 14 years and 563,079 work hours without a lost-time injury. This was a significant accomplishment for a work group that averages just 20 employees who serve 37,420 customers across nine counties.
- In May, Cane Run, Ohio Falls and Paddy's Run employees collectively achieved one year without a recordable injury.
  - Ohio Falls employees have also achieved three years without a recordable injury.
- Also in May, E.W. Brown employees completed one year, or more than 270,000 work hours, without a recordable injury.

LKE earned 10 communications awards in various categories during the recent Utility Communicators International conference. The 2018 Better Communications Competition receives entries from utilities of all sizes across the U.S. and Canada. The conference was held in Louisville this year.

KU has earned national recognition from the research firm Market Strategies. It is one of 15 utilities that have been designated a 2018 trusted utility brand by business customers. The research firm conducted a survey of 35 questions among almost 9,000 business consumers served by 60 of the largest utilities in the U.S.

The hearing for the Advanced Metering System (AMS) case was held on July 24th.

Variance Explanations

Higher YTD margins primarily due to higher sales volumes from favorable weather, resulting in higher retail electric base energy revenue of $23 million partially offset by lower demand revenue of $3 million, lower gas margins of $5 million and other margin components of $2 million.

Lower YTD O&M primarily due to the timing of plant maintenance costs ($3 million), lower materials ($3 million), lower labor costs ($3 million) and lower bad debt expense ($1 million).

(1) Full year forecast amount shown represents target.

(2) Net of cost recovery mechanisms and variable costs of production.

(3) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses

(4) The possible violation issues for YTD Actual is believed to be minimal risk.

(5) Excludes goodwill and other purchase accounting adjustments.

Significant Future Events

KPSC Orders are expected in the AMS, Tax Act and DSM/Energy Efficiency Program cases in Q3.

KU and LG&E expect to file a base rate case with the KPSC on September 28th (legal notice of intent to file a case made with KPSC August 27th; newspaper notices with requested rate changes begin September 21st).

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — June 2018

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 249	$ 248	$ 1	
Gas Revenues	13	13	(0)	
Total Revenues	262	261	1	
Cost of Sales:				
Fuel Electric Costs	68	68	(0)	
Gas Supply Expenses	2	2	(0)	
Purchased Power	5	5	0	
Other Cost of Production	3	3	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	5	7	1	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	6	0	
Total Cost of Sales	91	92	1	
Gross Margin:				
Electric Margin	162	159	3	
Gas Margin	10	10	0	
Total Gross Margin	172	169	3	
O&M	62	60	(2)	
Depreciation & Amortization	34	34	0	
Taxes, Other than Income	6	6	0	
Other income (expense)	2	(1)	2	
EBIT	72	68	3	
Interest Expense	19	20	1	
Income from Ongoing Operations before income taxes	52	48	4	
Income Tax Expense	10	8	(3)	
Net Income (loss) from ongoing operations	**42**	**40**	**2**	
Special Item - (Non Operating Income)	(0)	0	(0)	
Discontinued Operations	0	0	0	
Net Income (loss)	$ 42	$ 40	$ 2	
KY Regulated Financing Costs	(3)	$ (3)	1	
KY Regulated Net Income	$ 39	$ 37	$ 3	
Earnings Per Share - Ongoing	$ 0.06	$ 0.05	$ 0.01	

Note: Schedules may not sum due to rounding.

Case Nos. 2018-00294 and 2018-00295
Attachment to Filing Requirement
807 KAR 5:001 Sec. 16(7)(o)
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Arbough

Income Statement: Actual vs. Budget (YTD) - LKE Consolidated — June 2018

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,433	$ 1,390	$ 43	Due primarily to higher sales volumes from favorable weather.
Gas Revenues	185	197	(12)	Due primarily to lower sales volumes as a result of unfavorable weather in February and lower than budgeted YTD gas cost recovery.
Total Revenues	1,618	1,587	31	
Cost of Sales:				
Fuel Electric Costs	407	377	(30)	Due primarily to higher fuel costs related to higher sales volumes from favorable weather.
Gas Supply Expenses	81	87	6	Due primarily to lower gas volumes as a result of unfavorable weather in February and lower than budgeted YTD gas prices.
Purchased Power	31	31	0	
Other Cost of Production	18	18	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	30	34	5	Due primarily to elimination of some DSM programs in the 2018 filing with the KPSC.
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	36	37	1	
Total Cost of Sales	602	584	(18)	
Gross Margin:				
Electric Margin	914	897	17	See explanations above.
Gas Margin	102	106	(5)	See explanations above.
Total Gross Margin	1,016	1,003	13	
O&M	368	380	12	Lower primarily due to the timing of plant maintenance costs, lower materials, lower labor costs and lower bad debt expense.
Depreciation & Amortization	201	203	2	
Taxes, Other than Income	33	34	1	
Other income (expense)	(3)	(6)	3	
EBIT	411	380	30	
Interest Expense	113	118	4	
Income from Ongoing Operations before income taxes	297	263	35	
Income Tax Expense	60	57	(3)	
Net Income (loss) from ongoing operations	**237**	**205**	**32**	
Special Item - (Non Operating Income)	(9)	0	(9)	Due to Kentucky state tax reform resulting in a reduction of the Kentucky Corporate income tax, a $9 million deferred tax expense was recorded related to the revaluing of non-utility deferred taxes.
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 228	$ 205	$ 22	
KY Regulated Financing Costs	(18)	(19)	1	
KY Regulated Net Income	210	$ 187	$ 23	
Earnings Per Share - Ongoing	$ 0.31	$ 0.26	$ 0.06	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E — June 2018

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 571	$ 551	$ 19	Due primarily to higher sales volumes from favorable weather.
Gas Revenues	185	197	(12)	Due primarily to lower sales volumes as a result of unfavorable weather in February and lower than budgeted YTD gas cost recovery.
Total Revenues	756	749	7	
Cost of Sales:				
Fuel Electric Costs	160	149	(11)	Due primarily to higher fuel costs related to higher sales volumes from favorable weather.
Gas Supply Expenses	81	87	6	Due primarily to lower gas volumes as a result of unfavorable weather in February and lower than budgeted YTD gas prices.
Purchased Power	24	25	1	
Other Cost of Production	7	8	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	11	14	3	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	16	17	0	
Total Cost of Sales	299	298	(0)	
Gross Margin:				
Electric Margin	355	344	11	See explanations above.
Gas Margin	102	106	(5)	See explanations above.
Total Gross Margin	457	450	7	
O&M	163	166	2	
Depreciation & Amortization	82	83	1	
Taxes, Other than Income	17	18	0	
Other income (expense)	(3)	(4)	0	
EBIT	191	181	11	
Interest Expense	37	39	2	
Income from Ongoing Operations before income taxes	154	141	13	
Income Tax Expense	32	32	(0)	
Net Income (loss) from ongoing operations	**$ 121**	**$ 109**	**$ 12**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Actual vs. Budget (YTD) - KU — June 2018

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 887	$ 865	$ 22	Due primarily to higher sales volumes from favorable weather.
Gas Revenues	0	0	0	
Total Revenues	887	865	22	
Cost of Sales:				
Fuel Electric Costs	254	229	(25)	Due primarily to higher fuel costs related to higher sales volumes from favorable weather.
Gas Supply Expenses	0	0	0	
Purchased Power	25	31	6	Due primarily to lower than anticipated intercompany expense for native load fuel.
Other Cost of Production	10	11	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	19	21	2	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	20	20	0	
Total Cost of Sales	328	312	(16)	
Gross Margin:				
Electric Margin	559	553	6	See explanations above.
Gas Margin	0	0	0	
Total Gross Margin	559	553	6	
O&M	188	198	10	Primarily due to lower labor and burdens and lower outside service expense.
Depreciation & Amortization	119	120	1	
Taxes, Other than Income	16	16	0	
Other income (expense)	(0)	(2)	2	
EBIT	236	217	19	
Interest Expense	50	51	1	
Income from Ongoing Operations before income taxes	187	166	20	
Income Tax Expense	38	37	(2)	
Net Income (loss) from ongoing operations	**$ 148**	**$ 130**	**$ 19**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Forecast vs. Budget - LKE Consolidated — June 2018

($ Millions)

	Full Year			
	Q2 Forecast	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,853	$ 2,840	$ 14	Due primarily to higher sales volumes from favorable weather.
Gas Revenues	309	323	(13)	Due primarily to lower sales volumes as a result of unfavorable weather in February and lower than budgeted YTD gas cost recovery.
Total Revenues	3,163	3,163	0	
Cost of Sales:				
Fuel Electric Costs	788	762	(26)	Due primarily to higher fuel costs related to higher sales volumes from favorable weather.
Gas Supply Expenses	123	128	5	Due primarily to lower gas volumes as a result of unfavorable weather in February and lower than budgeted YTD gas prices.
Purchased Power	65	62	(3)	
Other Cost of Production	42	40	(3)	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	61	78	16	Due primarily to elimination of some DSM programs in the 2018 filing with the KPSC.
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	75	77	1	
Total Cost of Sales	1,155	1,146	(9)	
Gross Margin:				
Electric Margin	1,827	1,831	(4)	
Gas Margin	181	185	(5)	See explanations above.
Total Gross Margin	2,008	2,017	(9)	
O&M	752	752	0	
Depreciation & Amortization	408	410	2	
Taxes, Other than Income	66	67	1	
Other income (expense)	(4)	(10)	6	Due primarily to lower Pension non-service cost expense in the updated disclosures from Willis Towers Watson.
EBIT	778	778	0	
Interest Expense	233	241	7	Primarily due to lower debt balances and lower interest rates.
Income from Ongoing Operations before income taxes	545	537	8	
Income Tax Expense	110	117	7	
Net Income (loss) from ongoing operations	**434**	**420**	**$ 15**	
Special Item - (Non Operating Income)	(9)	0	(9)	Due to Kentucky state tax reform resulting in a reduction of the Kentucky Corporate income tax, a $9 million deferred tax expense was recorded related to the revaluing of non-utility deferred taxes.
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 425	$ 420	$ 5	
KY Regulated Financing Costs	(39)	(40)	1	
KY Regulated Net Income	$ 386	$ 380	$ 6	
Earnings Per Share - Ongoing	$ 0.53	$ 0.52	$ 0.01	

Note: Schedules may not sum due to rounding.

O&M | **June 2018**

($ Millions)

	MTD							
	Actual	**Budget**	**Total Variance**	**Labor & Burdens**	**Supplemental Contractors**	**Other Outside Services**	**Materials**	**Other**
Generation	14	15	1	(0)	0	1	0	(0)
Project Engineering	0	0	0	(0)	0	(0)	0	0
Transmission	5	3	(1)	(0)	(0)	(0)	(0)	(0)
Energy Supply and Analysis	1	1	0	(0)	0	0	0	0
Electric Distribution	8	6	(1)	(0)	(0)	(1)	0	(0)
Gas Distribution	4	3	(1)	(0)	(1)	0	0	(0)
Advanced Metering System	0	0	(0)	0	(0)	(0)	0	(0)
Safety and Technical Training	0	0	0	(0)	0	0	0	0
Environmental	1	1	0	(0)	0	0	0	0
Customer Services	8	8	(0)	(0)	(0)	0	0	(0)
Chief Operating Officer Total	**41**	**38**	**(2)**	**(1)**	**(1)**	**(0)**	**0**	**(1)**
Audit Services	0	0	(0)	(0)	0	0	0	0
Controller	1	1	0	0	0	0	0	0
Supply Chain	0	0	(0)	(0)	0	(0)	0	(0)
Information Technology	5	5	0	0	(0)	0	0	0
Treasurer	2	2	0	(0)	0	0	0	0
State Regulation and Rates	0	0	0	0	0	0	0	0
Other	0	0	0	(0)	0	(0)	0	0
Chief Financial Officer Total	**8**	**9**	**0**	**0**	**(0)**	**0**	**0**	**0**
General Counsel	**2**	**2**	**0**	**0**	**0**	**(0)**	**0**	**0**
Human Resources	**1**	**1**	**0**	**0**	**0**	**(0)**	**0**	**0**
Corporate	**7**	**8**	**1**	**1**	**0**	**0**	**(0)**	**(0)**
Communication	**1**	**1**	**0**	**(0)**	**0**	**(0)**	**0**	**0**
Utility Total	**59**	**58**	**(1)**	**(0)**	**(1)**	**(0)**	**1**	**(0)**
Nonutility	**3**	**2**	**(1)**	**0**	**0**	**(0)**	**0**	**(1)**
O&M Total MTD	**62**	**60**	**(2)**	**0**	**(1)**	**(0)**	**1**	**(1)**

	YTD							
	Actual	**Budget**	**Total Variance**	**Labor & Burdens**	**Supplemental Contractors**	**Other Outside Services**	**Materials**	**Other**
Generation	102	110	8	(0)	1	10	2	(5)
Project Engineering	0	0	0	(0)	0	(0)	0	0
Transmission	19	20	0	(0)	2	(1)	(0)	(0)
Energy Supply and Analysis	7	7	0	0	0	0	0	(0)
Electric Distribution	37	36	(1)	(1)	3	(3)	1	(0)
Gas Distribution	21	19	(1)	0	(2)	1	(0)	(0)
Advanced Metering System	1	0	(1)	0	(0)	(1)	(0)	(0)
Safety and Technical Training	3	3	0	0	0	0	(0)	0
Environmental	3	4	1	(0)	0	0	0	0
Customer Services	47	48	2	(0)	(0)	1	0	1
Chief Operating Officer Total	**239**	**247**	**8**	**(1)**	**3**	**8**	**2**	**(4)**
Audit Services	1	1	0	0	0	(0)	0	0
Controller	4	5	0	0	0	0	(0)	0
Supply Chain	2	2	0	0	(0)	(0)	(0)	0
Information Technology	28	30	2	2	(1)	0	0	0
Treasurer	12	12	0	(0)	0	0	0	0
State Regulation and Rates	2	2	(0)	0	0	0	(0)	0
Other	1	1	(0)	0	0	(1)	0	1
Chief Financial Officer Total	**50**	**52**	**2**	**2**	**(1)**	**(0)**	**(0)**	**1**
General Counsel	**9**	**9**	**(0)**	**0**	**0**	**(2)**	**0**	**1**
Human Resources	**3**	**3**	**0**	**0**	**(0)**	**(0)**	**0**	**0**
Corporate	**46**	**48**	**2**	**2**	**0**	**0**	**(0)**	**(0)**
Communication	**3**	**4**	**1**	**(0)**	**0**	**(0)**	**0**	**0**
Utility Total	**351**	**363**	**12**	**3**	**3**	**6**	**2**	**(1)**
Nonutility	**17**	**17**	**0**	**(0)**	**(0)**	**(1)**	**0**	**1**
O&M Total YTD	**368**	**380**	**12**	**3**	**3**	**5**	**2**	**(0)**

	Full Year							
	Forecast	**Budget**	**Total Variance**	**Labor & Burdens**	**Supplemental Contractors**	**Other Outside Services**	**Materials**	**Other**
Generation	211	216	5	(0)	1	2	4	(2)
Project Engineering	0	0	(0)	0	0	(0)	0	(0)
Transmission	38	38	(0)	(0)	2	(1)	(0)	(0)
Energy Supply and Analysis	13	13	(0)	0	0	(0)	0	(0)
Electric Distribution	76	75	(1)	(1)	4	(5)	1	(0)
Gas Distribution	44	39	(6)	0	(4)	(2)	0	(0)
Advanced Metering System	1	0	(1)	0	1	(0)	(0)	(3)
Safety and Technical Training	6	6	0	(0)	0	(0)	(0)	0
Environmental	7	8	1	(0)	0	0	(0)	1
Customer Services	98	97	(1)	(1)	(1)	1	0	(0)
Other	1	1	0	0	0	0	0	(0)
Chief Operating Officer Total	**496**	**493**	**(3)**	**(2)**	**5**	**(5)**	**5**	**(5)**
Audit Services	2	2	0	(0)	0	(0)	0	0
Controller	9	9	0	0	0	0	(0)	0
Supply Chain	4	4	(0)	0	(0)	(0)	(0)	(0)
Information Technology	58	58	0	2	(2)	0	0	(0)
Treasurer	23	23	0	(0)	0	(0)	0	0
State Regulation and Rates	5	5	(0)	0	0	0	(0)	(0)
Other	2	2	0	0	0	(1)	0	1
Chief Financial Officer Total	**103**	**103**	**1**	**2**	**(2)**	**(0)**	**(0)**	**1**
General Counsel	**18**	**18**	**0**	**0**	**0**	**(1)**	**0**	[illegible]
Human Resources	**7**	**7**	**(0)**	**0**	**(0)**	**(0)**	**0**	**0**
Corporate	**91**	**95**	**4**	**4**	**0**	**0**	**(0)**	**(0)**
Communication	**7**	**7**	**0**	**(0)**	**0**	**(0)**	**0**	**0**
Utility Total	**721**	**723**	**2**	**4**	**3**	**(7)**	**4**	**(3)**
Nonutility Total	**31**	**29**	**(1)**	**(0)**	**(0)**	**(1)**	**0**	**(0)**
O&M Total YTD	**752**	**752**	**0**	**4**	**3**	**(7)**	**4**	**(4)**

Note: Schedules may not sum due to rounding.

Financing Activities — June 2018

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB						
Beg Bal	$ 890.0	$ 890.0	$ 0.0	$ 890.0	$ 890.0	$ 0.0
End Bal	890.0	890.0	0.0	881.1	890.0	8.9
Ave Bal	**$ 887.4**	**$ 890.0**	**$ 2.55**	**$ 885.5**	**$ 890.0**	**$ 4.46**
Interest Exp	**$ 7.7**	**$ 9.0**	**$ 1.2**	**$ 16.2**	**$ 18.3**	**$ 2.2**
Rate	**1.73%**	**2.01%**	**0.27%**	**1.80%**	**2.03%**	**0.23%**
FMB/Sr Nts/Loan with PPL						
Beg Bal	$ 4,310.0	$ 4,310.0	$ 0.0	$ 4,310.0	$ 4,310.0	$ 0.0
End Bal	4,660.0	4,570.1	(89.9)	4,844.4	4,643.2	(201.2)
Ave Bal	**$ 4,469.7**	**$ 4,424.6**	**$ (45.08)**	**$ 4,577.2**	**$ 4,476.6**	**$ (100.59)**
Interest Exp	**$ 95.3**	**$ 94.6**	**$ (0.7)**	**$ 194.7**	**$ 191.9**	**$ (2.8)**
Rate	**4.24%**	**4.25%**	**0.01%**	**4.19%**	**4.22%**	**0.03%**
Short-term Debt						
Beg Bal	$ 468.9	$ 468.9	$ 0.0	$ 468.9	$ 468.9	$ 0.0
End Bal	415.1	569.1	154.0	614.2	722.7	108.5
Ave Bal (1)	**$ 381.7**	**$ 493.0**	**$ 111.3**	**$ 541.6**	**$ 595.8**	**$ 54.2**
Interest Exp	**$ 5.1**	**$ 8.7**	**$ 3.6**	**$ 11.7**	**$ 19.5**	**$ 7.8**
Rate	**2.65%**	**3.52%**	**0.86%**	**2.46%**	**3.41%**	**0.95%**
Unamortized Debt Expense Bonds						
Beg Bal	$ (41.6)	$ (41.6)	$ 0.0	$ (41.6)	$ (41.6)	$ 0.0
End Bal	(40.2)	(40.6)	(0.4)	(38.1)	(38.3)	(0.1)
Ave Bal	**$ (40.9)**	**$ (41.0)**	**$ (0.1)**	**$ (39.9)**	**$ (39.9)**	**$ (0.1)**
Total End Bal	**$ 5,924.9**	**$ 5,988.6**	**$ 63.7**	**$ 6,301.6**	**$ 6,217.6**	**$ (83.9)**
Total Average Bal	**$ 5,697.9**	**$ 5,766.6**	**$ 68.7**	**$ 5,898.1**	**$ 5,901.9**	**$ 3.9**
Total Expense Excl I/C (2)	**$ 113.4**	**$ 117.7**	**$ 4.4**	**$ 233.4**	**$ 240.8**	**$ 7.4**
Rate	**3.93%**	**4.03%**	**0.10%**	**3.88%**	**4.00%**	**0.12%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use an average monthly balance.

(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(3)	Letters of Credit Issued	Unused Capacity	Money Pool Loans
LKE	$ 375	$ 99		$ 276	
LG&E	700	383		317	$ 0
KU	598	133	$ 198	267	0
TOTAL	$ 1,673	$ 615	$ 198	$ 860	$ 0

(3) LG&E borrowed amount includes commercial paper issuances and $200M Term Loan. KU borrowed amount represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2018 Actual YTD	LKE 2018 Budget YTD	LG&E 2018 Actual YTD	LG&E 2018 Budget YTD	KU 2018 Actual YTD	KU 2018 Budget YTD
CFO pre-WC / Debt	16%	16%	26%	25%	25%	24%
CFO pre-WC + Interest / Interest	5.3	5.1	8.0	7.7	7.2	6.9
CFO pre-WC - Dividends / Debt	11%	10%	18%	18%	15%	14%
Debt to Capitalization	53%	53%	39%	38%	37%	37%

Credit Metrics Moody's	LKE 2018 BP 2019	LKE 2018 BP 2020	LG&E 2018 BP 2019	LG&E 2018 BP 2020	KU 2018 BP 2019	KU 2018 BP 2020
CFO pre-WC / Debt	14%	14%	19%	19%	19%	20%
CFO pre-WC + Interest / Interest	4.4	4.4	5.8	5.6	5.7	5.7
CFO pre-WC - Dividends / Debt	10%	10%	11%	10%	10%	11%
Debt to Capitalization	53%	52%	38%	38%	38%	38%

[1] Actuals represent a trailing 12 months.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2017	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated — June 2018

($ Millions)

	6/30/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 39	$ 14	$ 25	Increase primarily due to timing of cash receipts at the utilities.
Accounts Receivable (Trade)	402	452	(50)	Due primarily to differences in actual vs. budget accounts receivable lag factors.
Inventory	229	224	5	
Regulatory Assets Current	11	6	5	
Prepayments and other current assets	73	77	(3)	
Total Current Assets	754	773	(19)	
Property, Plant, and Equipment	12,270	12,381	(110)	
Intangible Assets	82	82	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	793	789	4	
Goodwill	997	997	0	
Other Long-term Assets	73	75	(2)	
Total Assets	**$ 14,970**	**$ 15,097**	**$ (127)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 274	$ 324	$ (50)	Primarily due to lower capital expenditures.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	59	58	1	
Derivative Liability	4	4	(0)	
Accrued Taxes	41	58	(17)	Primarily due to higher taxable income related to the methodology of recording Schedule M's in actuals versus the budget.
Regulatory Liabilities Current	71	68	3	
Other Current Liabilities	239	262	(23)	
Total Current Liabilities	688	775	(87)	
Debt - Affiliated Company	749	785	(36)	
Debt [(1)]	5,176	5,203	(27)	
Total Debt	5,925	5,989	(64)	
Deferred Tax Liabilities	878	901	(23)	
Investment Tax Credit	127	128	(0)	
Accum Provision for Pension & Related Benefits	259	253	6	
Asset Retirement Obligation	248	248	(0)	
Regulatory Liabilities Non Current	2,055	2,016	40	
Derivative Liability	17	20	(3)	
Other Liabilities	140	149	(9)	
Total Deferred Credits and Other Liabilities	3,725	3,715	10	
Equity	4,632	4,619	14	
Total Liabilities and Equity	**$ 14,970**	**$ 15,097**	**$ (127)**	

[(1)] Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

June 2018

($ Millions)

	6/30/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 19	$ 5	$ 14	Increase primarily due to timing of cash receipts.
Accounts Receivable (Trade)	176	203	(27)	Due primarily to differences in actual vs. budget accounts receivable lag factors.
Inventory	101	96	4	
Regulatory Assets Current	11	7	3	
Prepayments and other current assets	44	50	(5)	
Total Current Assets	351	362	(11)	
Property, Plant, and Equipment	5,431	5,486	(56)	
Intangible Assets	6	6	0	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	405	404	1	
Goodwill	0	0	0	
Other Long-term Assets	22	14	8	
Total Assets	**$ 6,215**	**$ 6,273**	**$ (57)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 153	$ 193	$ (40)	Primarily due to lower capital expenditures.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	28	27	1	
Derivative Liability	4	4	(0)	
Accrued Taxes	23	19	4	
Regulatory Liabilities Current	34	30	4	
Other Current Liabilities	72	84	(12)	Primarily due to ARO reclassification from current to non-current in actuals and a decrease in customer advances versus the budget which assumed a static balance as of December 2017 when the budget was finalized.
Total Current Liabilities	314	358	(43)	
Debt - Affiliated Company	0	0	0	
Debt [1]	1,991	1,988	3	
Total Debt	1,991	1,988	3	
Deferred Tax Liabilities	581	594	(13)	
Investment Tax Credit	35	35	(0)	
Accum Provision for Pension & Related Benefits	0	(16)	16	Difference due to reclassification of prepaid pension balance to other long term assets.
Asset Retirement Obligation	96	92	4	
Regulatory Liabilities Non Current	879	862	17	
Derivative Liability	17	20	(3)	
Other Liabilities	81	84	(3)	
Total Deferred Credits and Other Liabilities	1,688	1,670	18	
Equity	2,222	2,256	(34)	
Total Liabilities and Equity	**$ 6,215**	**$ 6,273**	**$ (57)**	

[1] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

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Balance Sheet - KU June 2018

($ Millions)

	6/30/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 20	$ 5	$ 14	Increase primarily due to timing of cash receipts.
Accounts Receivable (Trade)	225	248	(23)	
Inventory	129	128	1	
Regulatory Assets Current	0	(2)	2	
Prepayments and other current assets	47	51	(4)	
Total Current Assets	420	430	(10)	
Property, Plant, and Equipment	6,830	6,886	(56)	
Intangible Assets	12	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	386	385	1	
Goodwill	0	0	0	
Other Long-term Assets	74	59	16	Primarily due to the reclassification of prepaid pension balance from Accum Provision for Pension & Related Benefits.
Total Assets	**$ 7,723**	**$ 7,773**	**$ (50)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 163	$ 178	$ (15)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	31	31	0	
Derivative Liability	0	0	0	
Accrued Taxes	23	16	6	
Regulatory Liabilities Current	37	38	(1)	
Other Current Liabilities	118	120	(1)	
Total Current Liabilities	372	383	(11)	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,461	2,491	(30)	
Total Debt	2,461	2,491	(30)	
Deferred Tax Liabilities	690	709	(19)	
Investment Tax Credit	93	93	(0)	
Accum Provision for Pension & Related Benefits	0	(13)	13	Difference due to reclassification of prepaid pension balance to other long term assets.
Asset Retirement Obligation	153	156	(4)	
Regulatory Liabilities Non Current	1,112	1,090	21	
Derivative Liability	0	0	0	
Other Liabilities	36	39	(2)	
Total Deferred Credits and Other Liabilities	2,083	2,074	9	
Equity	2,807	2,825	(19)	
Total Liabilities and Equity	**$ 7,723**	**$ 7,773**	**$ (50)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

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KU and LG&E Combined
Reconciliation of Allowed Return to
12 months ended June 2018 Regulatory Return
and ROE from Ongoing Operations

Allowed Return [(1)]		9.71%	
Adjustments (net tax):			
Change in capitalization - non mechanism	0.18%		Growth in capitalization (rate base) between rate cases does not earn a return
Change in ROE from average mechanism rate base growth	0.00%		Mechanisms have a real-time return
Change in weighted cost of debt	0.01%		
Change in margins	0.33%		Slightly higher revenue
Change in allowed expenses	0.52%		Lower expense
		1.03%	
Actual Regulated ROE		10.74%	

[(1)] Based on the most recent base rate filings for a test year ending 6/30/18 for the KPSC and a test year ending 12/31/16 (with adjustments for year ending 12/31/2018) for VA and FERC Formula Rate Filing 12/31/17.
The KPSC authorized ROE is 9.7% after 7/1/17.

PPL companies

Performance Report

July 2018

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Kentucky Regulated Dashboard — July 2018

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees[1]	1.17	2.01	1.42	1.13	1.30	0.97
Employee lost-time incidents	0	2	2	6	6	9
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,208	3,236	20,337	19,791	34,250	33,704
Utility EFOR	3.5%	5.0%	2.5%	5.0%	N/A	5.0%
Utility EAF	93.9%	92.9%	84.3%	84.0%	N/A	83.7%
Combined SAIFI	0.09	0.14	0.52	0.66	N/A	0.99
Combined SAIDI (minutes)	10.79	14.67	56.82	61.34	N/A	91.90
GwH Sales	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Residential	1,093	1,067	6,637	6,238	10,820	10,502
Commercial	773	748	4,709	4,562	8,018	7,815
Industrial	790	825	5,320	5,425	9,177	9,321
Municipals	169	169	1,054	1,045	1,822	1,778
Other	251	255	1,620	1,640	2,761	2,822
Off-System Sales	37	13	416	111	616	150
Total	3,112	3,077	19,756	19,020	33,216	32,389
Weather-Normalized Sales Growth			**TTM**			
Residential			0.11%			
Commercial			-0.66%			
Industrial			-1.29%			
Municipal			-4.40%			
Other			-0.98%			
Total			-0.84%			

	Current Month		YTD		Full Year	
Margins ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Electric Margins	$170	$171	$1,084	$1,068	$1,822	$1,831
Gas Margins	$9	$9	$111	$116	$181	$185
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Total	$94	$119	$620	$757	$1,235	$1,277
O&M ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
O&M – Management View[2]	$66	$61	$434	$441	$752	$752
O&M – GAAP View[3]	$74	$72	$490	$505	$856	$869
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,470	3,603	3,470	3,603	3,592	3,597
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	2	0	5	N/A	8
NERC Possible Violations[4]	0	0	7	4	N/A	8

	TTM	Full Year	
Financial Metrics	**Actual**	**Forecast**	**Budget**
Utility ROE[5]	10.5%	9.8%	9.6%
Average Utility Capitalization ($ millions)	$9,209	$9,486	$9,527

Major Developments

A July 20th storm event caused extensive, widespread damage across the LKE system, taking down 1,360 wires, and damaging 209 poles and other equipment across the Company's distribution and transmission infrastructure. Nearly 175,000 customers were impacted, ranking this among the top five storms to affect the LKE system. Crews worked as quickly and safely as possible to assess damage, make repairs and restore service with additional help provided by partner utilities from Wisconsin, Indiana, Ohio, Missouri, Tennessee, Arkansas, and Kentucky. Winds measured at 83 miles per hour damaged two cooling towers at the EW Brown plant leading to a Brown Unit 3 outage. Total costs are expected to be approximately $16 million, split evenly between capital and operating expenses.

Recognition:
- LKE was recognized by Site Selection magazine as a top ten utility in the area of economic development. The Company has received this honor six times since 2012.
- LKE was recognized as one of the top employee-giving campaigns for the 2018 Fund for the Arts campaign.
- LKE was one of 13 Interactive Voice Response ("IVRs") selected to receive the 2018 Gold Stethoscope Award as a "Balanced Company" by IVR Doctors and Market Strategies International.
- LKE will also receive the bronze Best Practice Award from Chartwell in the self-service category for its IVR Time Extension Automation project.

KU and the IBEW recently ratified a three-year labor agreement through 2021. The agreement covers approximately 68 employees.

Oral arguments were presented on August 2nd at the U.S. Court of Appeals for the Sixth Circuit in the Sierra Club and Kentucky Waterways Alliance appeal of the ruling by the U.S. District Court for the Eastern District of Kentucky granting LKE's motion to dismiss the citizen suit filed by these parties related to water discharges at KU's EW Brown power plant. A decision is likely several months away, and any party dissatisfied with the decision may petition for discretionary review by the U.S. Supreme Court.

Variance Explanations

Higher margins YTD primarily due to higher sales volumes from favorable weather, resulting in higher retail electric base energy revenue of $24 million partially offset by lower demand revenue of $4 million, lower gas margins of $5 million and other margin components of $3 million.

Higher O&M MTD primarily due to July 20th storm event ($7.5 million), partially offset by lower labor and burdens ($2 million).

Lower O&M YTD primarily due to the timing of plant maintenance costs ($6.5m), lower labor costs ($4m), lower materials ($2m), and lower vegetation management ($1m); partially offset by the July 20th storm event (-$7.5m).

Lower financing costs YTD primarily due to lower than anticipated interest rates.

(1) Full year forecast amount shown represents target.

(2) Net of cost recovery mechanisms and variable costs of production.

(3) Includes Management O&M, variable cost of production and mechanism operation and maintenance expenses

(4) The possible violation issues for YTD Actual is believed to be minimal risk.

Note: Schedules may not sum due to rounding.

Significant Future Events

KPSC Orders are expected in the AMS, Tax Act and DSM/Energy Efficiency Program cases in Q3.

KU and LG&E expect to file a base rate case with the KPSC on September 28th (legal notice of intent to file a case August 27th; newspaper notices with requested rate changes begin September 21st).

Income Statement: Actual vs. Budget (Month) - LKE Consolidated — July 2018

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 260	$ 267	$ (6)	Due primarily to lower fuel prices, lower DSM program spend, and lower ECR capital and expenses.
Gas Revenues	12	12	(0)	
Total Revenues	272	278	(7)	
Cost of Sales:				
Fuel Electric Costs	71	73	2	
Gas Supply Expenses	2	2	(0)	
Purchased Power	5	6	0	
Other Cost of Production	3	3	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	5	8	3	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	6	6	0	
Total Cost of Sales	92	98	6	
Gross Margin:				
Electric Margin	170	171	(1)	
Gas Margin	9	9	(0)	
Total Gross Margin	179	180	(1)	
O&M	66	61	(5)	Higher primarily due to July 20th storm event, partially offset by lower labor and burdens.
Depreciation & Amortization	34	34	1	
Taxes, Other than Income	6	6	0	
Other income (expense)	(1)	(1)	(0)	
EBIT	73	79	(6)	
Interest Expense	20	20	1	
Income from Ongoing Operations before income taxes	54	59	(5)	
Income Tax Expense	11	15	4	
Net Income (loss) from ongoing operations	**43**	**44**	**(1)**	
Special Item - (Non Operating Income)	0	0	0	
Discontinued Operations	0	0	0	
Net Income (loss)	$ 43	$ 44	$ (1)	
KY Regulated Financing Costs	(3)	$ (3)	1	
KY Regulated Net Income	$ 40	$ 40	$ (0)	
Earnings Per Share - Ongoing	$ 0.06	$ 0.06	$ 0.00	

Note: Schedules may not sum due to rounding.

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Income Statement: Actual vs. Budget (YTD) - LKE Consolidated				July 2018
($ Millions)				
	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,693	$ 1,656	$ 36	Due primarily to higher sales volumes from favorable weather, partially offset by lower demand, lower DSM program spend, and lower ECR capital and expenses.
Gas Revenues	197	209	(12)	Due primarily to lower sales volumes as a result of unfavorable weather in February and lower than budgeted YTD gas cost recovery.
Total Revenues	1,890	1,866	24	
Cost of Sales:				
Fuel Electric Costs	478	450	(28)	Due primarily to higher fuel costs related to higher sales volumes from favorable weather.
Gas Supply Expenses	82	88	6	Due primarily to lower gas volumes as a result of unfavorable weather in February and lower than budgeted YTD gas prices.
Purchased Power	36	37	1	
Other Cost of Production	21	22	0	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	35	42	8	Due primarily to elimination of some DSM programs in the 2018 filing with the KPSC and lower ECR expenses.
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	42	43	1	
Total Cost of Sales	694	682	(13)	
Gross Margin:				
Electric Margin	1,084	1,068	16	See explanations above.
Gas Margin	111	116	(5)	See explanations above.
Total Gross Margin	1,195	1,184	11	
O&M	434	441	7	Lower primarily due to the timing of plant maintenance costs, lower labor costs, lower materials, and lower vegetation management; partially offset by the July 20th storm event.
Depreciation & Amortization	235	237	2	
Taxes, Other than Income	39	39	1	
Other income (expense)	(4)	(7)	3	
EBIT	484	459	25	
Interest Expense	133	138	5	Lower primarily due to lower than anticipated interest rates.
Income from Ongoing Operations before income taxes	351	321	30	
Income Tax Expense	71	72	1	
Net Income (loss) from ongoing operations	**280**	**249**	**31**	
Special Item - (Non Operating Income)	(9)	0	(9)	Due to Kentucky state tax reform resulting in a reduction of the Kentucky Corporate income tax, a $9 million deferred tax expense was recorded related to the revaluing of non-utility deferred taxes.
Discontinued Operations	0	0	0	
Net Income (loss)	$ 271	$ 249	$ 21	
KY Regulated Financing Costs	(21)	(22)	1	
KY Regulated Net Income	250	$ 227	$ 23	
Earnings Per Share - Ongoing	$ 0.37	$ 0.31	$ 0.06	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) - LG&E — July 2018

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 682	$ 664	$ 18	Due primarily to higher sales volumes from favorable weather, partially offset by lower DSM program spend, and lower ECR capital and expenses.
Gas Revenues	197	209	(12)	Due primarily to lower sales volumes as a result of unfavorable weather in February and lower than budgeted YTD gas cost recovery.
Total Revenues	879	874	5	
Cost of Sales:				
Fuel Electric Costs	189	177	(12)	Due primarily to higher fuel costs related to higher sales volumes from favorable weather.
Gas Supply Expenses	82	88	6	Due primarily to lower gas volumes as a result of unfavorable weather in February and lower than budgeted YTD gas prices.
Purchased Power	28	30	2	
Other Cost of Production	9	9	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	13	17	4	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	19	19	0	
Total Cost of Sales	340	341	2	
Gross Margin:				
Electric Margin	428	416	12	See explanations above.
Gas Margin	111	116	(5)	See explanations above.
Total Gross Margin	539	532	7	
O&M	193	193	0	
Depreciation & Amortization	96	97	1	
Taxes, Other than Income	20	20	1	
Other income (expense)	(4)	(4)	0	
EBIT	227	218	9	
Interest Expense	44	46	2	
Income from Ongoing Operations before income taxes	183	172	11	
Income Tax Expense	40	40	0	
Net Income (loss) from ongoing operations	**$ 143**	**$ 132**	**$ 11**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

Income Statement: Actual vs. Budget (YTD) - KU

July 2018

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 1,037	$ 1,021	$ 16	Due primarily to higher sales volumes from favorable weather, partially offset by lower demand, lower DSM program spend, and lower ECR capital and expenses.
Gas Revenues	0	0	0	
Total Revenues	1,037	1,021	16	
Cost of Sales:				
Fuel Electric Costs	296	274	(22)	Due primarily to higher fuel costs related to higher sales volumes from favorable weather.
Gas Supply Expenses	0	0	0	
Purchased Power	28	34	6	Due primarily to lower than anticipated intercompany expense for native load fuel.
Other Cost of Production	12	13	1	
Mechanism - ECR, DSM & GLT - Operation and Maintenance	22	25	3	
Mechanism - ECR, DSM & GLT - Depreciation and Property Tax	23	24	1	
Total Cost of Sales	381	370	(12)	
Gross Margin:				
Electric Margin	656	651	5	See explanations above.
Gas Margin	0	0	0	
Total Gross Margin	656	651	5	
O&M	222	229	7	Primarily due to lower labor and reduced plant maintenance.
Depreciation & Amortization	139	140	1	
Taxes, Other than Income	19	19	0	
Other income (expense)	(0)	(2)	2	
EBIT	276	261	15	
Interest Expense	58	60	2	
Income from Ongoing Operations before income taxes	218	202	16	
Income Tax Expense	46	45	(1)	
Net Income (loss) from ongoing operations	**$ 172**	**$ 156**	**$ 16**	

Note: Schedules may not sum due to rounding and exclude purchase accounting adjustments and corresponding goodwill.

O&M — July 2018

($ Millions)

	MTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	14	15	1	0	0	0	0	0
Project Engineering	0	0	0	(0)	(0)	0	0	0
Transmission	3	4	0	(0)	0	(0)	(0)	0
Energy Supply and Analysis	1	1	0	0	0	0	0	(0)
Electric Distribution	13	7	(6)	(1)	(4)	(1)	(1)	(0)
Gas Distribution	4	3	(1)	0	(1)	0	0	(0)
Advanced Metering System	0	0	(0)	0	0	0	(0)	(0)
Safety and Technical Training	0	1	0	0	0	0	0	0
Environmental	0	1	0	(0)	0	0	0	0
Customer Services	9	8	(1)	0	0	0	0	(1)
Chief Operating Officer Total	**46**	**40**	**(7)**	**(1)**	**(4)**	**(1)**	**(0)**	**(1)**
Audit Services	0	0	(0)	(0)	0	0	0	(0)
Controller	1	1	0	0	0	0	(0)	0
Supply Chain	0	0	0	0	(0)	(0)	(0)	0
Information Technology	4	5	1	0	(0)	0	0	0
Treasurer	2	2	0	0	0	0	0	0
State Regulation and Rates	0	0	0	0	0	0	(0)	0
Other	0	0	0	0	0	(0)	0	0
Chief Financial Officer Total	**8**	**9**	**1**	**0**	**(0)**	**0**	**0**	**0**
General Counsel	**1**	**1**	**0**	**0**	**0**	**(0)**	**0**	**0**
Human Resources	**0**	**1**	**0**	**0**	**0**	**(0)**	**(0)**	**0**
Corporate	**8**	**8**	**0**	**0**	**0**	**0**	**(0)**	**(0)**
Communication	**0**	**1**	**0**	**0**	**0**	**(0)**	**0**	**0**
Utility Total	**64**	**59**	**(5)**	**0**	**(4)**	**(1)**	**(0)**	**(1)**
Nonutility	**2**	**2**	**0**	**0**	**(0)**	**(0)**	**0**	**0**
O&M Total MTD	**66**	**61**	**(5)**	**0**	**(4)**	**(1)**	**(0)**	**(0)**

	YTD							
	Actual	Budget	Total Variance	Labor & Burdens	Supplemental Contractors	Other Outside Services	Materials	Other
Generation	116	125	8	0	1	10	2	(5)
Project Engineering	0	0	0	(0)	(0)	(0)	0	0
Transmission	23	24	1	(0)	3	(1)	(0)	(0)
Energy Supply and Analysis	8	8	0	0	0	0	0	(0)
Electric Distribution	50	43	(8)	(2)	(1)	(4)	(0)	(1)
Gas Distribution	25	23	(2)	0	(3)	1	0	(0)
Advanced Metering System	1	0	(1)	0	0	(0)	(0)	(1)
Safety and Technical Training	3	4	1	0	0	0	(0)	0
Environmental	4	4	1	(0)	0	0	0	1
Customer Services	56	56	1	(0)	(0)	1	0	0
Chief Operating Officer Total	**285**	**287**	**1**	**(2)**	**(1)**	**7**	**2**	**(5)**
Audit Services	1	1	0	0	0	(0)	0	0
Controller	5	5	0	0	0	0	(0)	0
Supply Chain	2	2	0	0	(0)	(0)	(0)	0
Information Technology	32	35	3	2	(1)	1	0	0
Treasurer	14	14	0	(0)	0	0	0	0
State Regulation and Rates	3	3	(0)	0	0	0	(0)	0
Other	1	1	(0)	0	0	(1)	0	1
Chief Financial Officer Total	**58**	**61**	**3**	**2**	**(1)**	**(0)**	**(0)**	**2**
General Counsel	**10**	**10**	**(0)**	**0**	**0**	**(2)**	**0**	**2**
Human Resources	**4**	**4**	**0**	**0**	**(0)**	**(0)**	**0**	**0**
Corporate	**54**	**56**	**2**	**2**	**0**	**0**	**(0)**	**(0)**
Communication	**4**	**4**	**1**	**0**	**0**	**(0)**	**1**	**0**
Utility Total	**415**	**422**	**7**	**3**	**(1)**	**5**	**2**	**(2)**
Nonutility	**19**	**19**	**0**	**(0)**	**(0)**	**(1)**	**0**	**1**
O&M Total YTD	**434**	**441**	**7**	**3**	**(1)**	**4**	**2**	**(1)**

Note: Schedules may not sum due to rounding.

Financing Activities July 2018

($ Millions)

Balance Sheet	YTD Actual	YTD Budget	YTD Variance
PCB			
Beg Bal	$ 890.0	$ 890.0	$ 0.0
End Bal	881.1	890.0	8.9
Ave Bal	**$ 886.6**	**$ 890.0**	**$ 3.35**
Interest Exp	**$ 9.0**	**$ 10.5**	**$ 1.5**
Rate	**1.72%**	**2.01%**	**0.29%**
FMB/Sr Nts/Loan with PPL			
Beg Bal	$ 4,310.0	$ 4,310.0	$ 0.0
End Bal	4,660.0	4,570.1	(89.9)
Ave Bal	**$ 4,491.3**	**$ 4,442.8**	**$ (48.45)**
Interest Exp	**$ 111.8**	**$ 110.8**	**$ (1.0)**
Rate	**4.23%**	**4.24%**	**0.01%**
Short-term Debt			
Beg Bal	$ 468.9	$ 468.9	$ 0.0
End Bal	381.6	555.7	174.1
Ave Bal (1)	**$ 382.2**	**$ 500.9**	**$ 118.7**
Interest Exp	**$ 6.0**	**$ 10.3**	**$ 4.4**
Rate	**2.66%**	**3.51%**	**0.85%**
Unamortized Debt Expense Bonds			
Beg Bal	$ (41.6)	$ (41.6)	$ 0.0
End Bal	(39.8)	(40.2)	(0.4)
Ave Bal	**$ (40.7)**	**$ (40.9)**	**$ (0.2)**
Total End Bal	**$ 5,882.8**	**$ 5,975.5**	**$ 92.7**
Total Average Bal	**$ 5,719.4**	**$ 5,792.7**	**$ 73.4**
Total Expense Excl I/C (2)	**$ 132.9**	**$ 138.2**	**$ 5.2**
Rate	**3.92%**	**4.02%**	**0.10%**

(1) Short-term Debt YTD actual reflects average daily balances. All other average balances use an average monthly balance.
(2) Total expense line includes additional revolving credit items. Total will not match sum of PCB, FMB, and STD.

Credit Facilities ($ Millions)	Committed Capacity	Borrowed(3)	Letters of Credit Issued	Unused Capacity	Money Pool Loans
LKE	$ 375	$ 96		$ 279	
LG&E	700	357		343	$ 0
KU	598	129	$ 198	271	0
TOTAL	$ 1,673	$ 582	$ 198	$ 893	$ 0

(3) LG&E borrowed amount includes commercial paper issuances and $200M Term Loan. KU borrowed amount represent commercial paper issuances. LKE borrowed amount includes bank revolver and debt with PPL.

Credit Metrics[1] Moody's	LKE 2018 Actual YTD	LKE 2018 Budget YTD	LG&E 2018 Actual YTD	LG&E 2018 Budget YTD	KU 2018 Actual YTD	KU 2018 Budget YTD
CFO pre-WC / Debt	16%	15%	26%	25%	25%	23%
CFO pre-WC + Interest / Interest	5.2	5.1	7.9	7.6	7.1	6.8
CFO pre-WC - Dividends / Debt	11%	10%	18%	18%	14%	14%
Debt to Capitalization	52%	53%	38%	38%	37%	37%

Credit Metrics Moody's	LKE 2018 BP 2019	LKE 2018 BP 2020	LG&E 2018 BP 2019	LG&E 2018 BP 2020	KU 2018 BP 2019	KU 2018 BP 2020
CFO pre-WC / Debt	14%	14%	19%	19%	19%	20%
CFO pre-WC + Interest / Interest	4.4	4.4	5.8	5.6	5.7	5.7
CFO pre-WC - Dividends / Debt	10%	10%	11%	10%	10%	11%
Debt to Capitalization	53%	52%	38%	38%	38%	38%

[1] Actuals represent a trailing 12 months.

Financial Strength Factor (40% Weighting) -- Standard Business Risk Grid:

Moody's Thresholds	Sub-Factor Weighting	A	Baa	Ba
CFO pre-WC / Debt	15.0%	22% - 30%	13% - 22%	5% - 13%
CFO pre-WC + Interest / Interest	7.5%	4.5x - 6x	3x - 4.5x	2x - 3x
CFO pre-WC - Dividends / Debt	10.0%	17% - 25%	9% - 17%	0% - 9%
Debt / Capitalization	7.5%	35% - 45%	45% - 55%	55% - 65%

As of December 31, 2017	Senior Unsecured	Senior Secured	Commercial Paper
Issuer	Moody's	Moody's	Moody's
LKE	Baa1		
LG&E		A1	P-2
KU		A1	P-2

Definitions

Issuers assessed **A** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.

Obligations rated **Baa** are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.

Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.

Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Balance Sheet - LKE Consolidated July 2018

($ Millions)

	7/31/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 20	$ 15	$ 5	
Accounts Receivable (Trade)	416	466	(51)	Due primarily to differences in actual vs. budget accounts receivable lag factors. The lag factors have been updated in the forecast.
Inventory	234	224	10	
Deferred Income Taxes	0	0	0	
Regulatory Assets Current	10	2	8	
Prepayments and other current assets	77	80	(3)	
Total Current Assets	757	787	(30)	
Property, Plant, and Equipment	12,318	12,449	(130)	
Intangible Assets	81	81	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	792	788	5	
Goodwill	997	997	0	
Other Long-term Assets	73	76	(3)	
Total Assets	**$ 15,020**	**$ 15,179**	**$ (158)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 301	$ 336	$ (35)	Primarily due to lower capital expenditures and timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	59	58	1	
Derivative Liability	4	4	(1)	
Accrued Taxes	60	79	(18)	Primarily due to the deferred taxes on TCJA credit in which actuals were recorded on the regulatory liability balance through June and 2018 Budget had spread the deferreds evenly over the year. Since TCJA regulatory liability builds up in first part of year and begins to amortize in latter part of year there is a difference in methodology for the 2018BP between budget and actuals. This has been addressed in the forecast.
Regulatory Liabilities Current	76	77	(2)	
Other Current Liabilities	241	279	(38)	Primarily due to decrease in credit cash adjustment for outstanding checks not yet funded versus the budget which assumed a static balance as of December 2017 when the budget was finalized and settlement of WKE indemnification.
Total Current Liabilities	741	834	(92)	
Debt - Affiliated Company	746	785	(40)	
Debt [(1)]	5,137	5,190	(53)	
Total Debt	5,883	5,976	(93)	
Deferred Tax Liabilities	876	901	(25)	
Investment Tax Credit	127	127	(0)	
Accum Provision for Pension & Related Benefits	262	252	9	
Asset Retirement Obligation	244	242	1	
Regulatory Liabilities Non Current	2,055	2,013	42	
Derivative Liability	16	20	(4)	
Other Liabilities	141	150	(8)	
Total Deferred Credits and Other Liabilities	3,721	3,706	15	
Equity	4,675	4,664	11	
Total Liabilities and Equity	**$ 15,020**	**$ 15,179**	**$ (158)**	

(1) Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.

Balance Sheet - LG&E

July 2018

($ Millions)

	7/31/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 9	$ 5	$ 4	
Accounts Receivable (Trade)	178	209	(31)	Due primarily to differences in actual vs. budget accounts receivable lag factors. The lag factors have been updated in the forecast.
Inventory	103	102	1	
Regulatory Assets Current	10	5	5	
Prepayments and other current assets	51	51	(0)	
Total Current Assets	351	372	(21)	
Property, Plant, and Equipment	5,451	5,523	(72)	
Intangible Assets	6	6	0	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	404	403	1	
Goodwill	0	0	0	
Other Long-term Assets	22	14	8	
Total Assets	**$ 6,235**	**$ 6,318**	**$ (84)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 171	$ 199	$ (28)	Primarily due to lower capital expenditures and timing of actuals.
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	29	27	1	
Derivative Liability	4	4	(1)	
Accrued Taxes	34	30	4	
Regulatory Liabilities Current	34	35	(0)	
Other Current Liabilities	69	89	(20)	Primarily due to ARO reclassification from current to non-current in actuals, a decrease in credit cash adjustment for outstanding checks not yet funded and a decrease in customer advances versus the budget which assumed a static balance as of December 2017 when the budget was finalized.
Total Current Liabilities	341	385	(44)	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	1,965	1,989	(24)	
Total Debt	1,965	1,989	(24)	
Deferred Tax Liabilities	581	594	(13)	
Investment Tax Credit	35	35	(0)	
Accum Provision for Pension & Related Benefits	0	(17)	17	Difference due to reclassification of prepaid pension balance to other long term assets.
Asset Retirement Obligation	93	90	3	
Regulatory Liabilities Non Current	878	860	18	
Derivative Liability	16	20	(4)	
Other Liabilities	82	84	(3)	
Total Deferred Credits and Other Liabilities	1,685	1,666	19	
Equity	2,244	2,279	(35)	
Total Liabilities and Equity	**$ 6,235**	**$ 6,318**	**$ (84)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.

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Balance Sheet - KU

July 2018

($ Millions)

	7/31/2018	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 11	$ 5	$ 6	
Accounts Receivable (Trade)	237	256	(19)	
Inventory	131	122	9	
Regulatory Assets Current	0	(3)	3	
Prepayments and other current assets	45	52	(7)	
Total Current Assets	424	433	(9)	
Property, Plant, and Equipment	6,857	6,918	(60)	
Intangible Assets	12	13	(0)	
Other Property and Investments	0	0	0	
Regulatory Assets Non Current	386	385	1	
Goodwill	0	0	0	
Other Long-term Assets	74	59	14	Primarily due to the reclassification of prepaid pension balance from Accum Provision for Pension & Related Benefits.
Total Assets	**$ 7,754**	**$ 7,807**	**$ (54)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 165	$ 181	$ (15)	
Dividends Payable to Affiliated Companies	0	0	0	
Customer Deposits	31	31	0	
Derivative Liability	0	0	0	
Accrued Taxes	33	28	5	
Regulatory Liabilities Current	41	43	(1)	
Other Current Liabilities	123	128	(5)	
Total Current Liabilities	393	410	(16)	
Debt - Affiliated Company	0	0	0	
Debt [(1)]	2,448	2,477	(29)	
Total Debt	2,448	2,477	(29)	
Deferred Tax Liabilities	690	709	(19)	
Investment Tax Credit	93	93	(0)	
Accum Provision for Pension & Related Benefits	0	(13)	13	Difference due to reclassification of prepaid pension balance to other long term assets.
Asset Retirement Obligation	150	152	(2)	
Regulatory Liabilities Non Current	1,113	1,090	23	
Derivative Liability	0	0	0	
Other Liabilities	37	39	(2)	
Total Deferred Credits and Other Liabilities	2,082	2,069	13	
Equity	2,831	2,852	(21)	
Total Liabilities and Equity	**$ 7,754**	**$ 7,807**	**$ (54)**	

[(1)] Includes all ST and LT debt.

Note: Schedules may not sum due to rounding and excludes purchase accounting adjustments.