Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Sections 14(1), 14(2), 14(3), 14(4)
Sponsoring Witness: Edwin R. Staton

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 No. 1.

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

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

Section 14(4)
LG&E 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: 156853
Visit https://app.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

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

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

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 5th day of November, 2014, in the 223rd year of the Commonwealth.

Alison Lundergan Grimes

Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
156853/0032196

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(1)
Sponsoring Witness: Edwin R. Staton

Description of Filing Requirement:

A statement of the reason the adjustment is required.

Response:

See Application.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(2)
Sponsoring Witness: Edwin R. Staton

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 LG&E is Louisville Gas and Electric Company. It has never done business in any state under an assumed name and has never filed a Certificate of Assumed Name as may be required by KRS 365.015. Therefore, the filing of a copy of any such certificate as required by this Filing Requirement is not necessary.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(3)
Sponsoring Witness: Edwin R. Staton

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.

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

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

PUBLIC SERVICE COMMISSION
OF KENTUCKY

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

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. T

RATE

Basic Service Charge:	$18.00 per month	I
Plus an Energy Charge of:	$ 0.07618 per kWh	R

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

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

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

DUE DATE OF BILL
Customer's payment will be due within 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: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate **RTOD-Energy** N

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:	$18.00 per month
Plus an Energy Charge:	
Off Peak Hours:	$0.05271 per kWh
On Peak Hours:	$0.21483 per kWh

ADJUSTMENT CLAUSES

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

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

Standard Rate **RTOD-Energy**

Residential Time-of-Day Energy Service N

DETERMINATION OF PRICING PERIODS

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

Summer Months of May through September

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

All Other Months of October continuously through April

	Off Peak	On-Peak
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.

Standard Rate

RTOD-Demand
Residential Time-of-Day Demand Service

N

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:	$18.00 per month
Plus an Energy Charge:	$ 0.04008 per kWh
Plus a Demand Charge:	
Off Peak Hours:	$ 2.95 per kW
On Peak Hours:	$10.90 per kW

ADJUSTMENT CLAUSES

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

DETERMINATION OF PRICING PERIODS

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

Summer Months of May through September

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

All Other Months of October continuously through April

	Off Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM - 11 AM
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: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate **VFD**

Volunteer Fire Department Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

DEFINITION

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

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

RATE

Basic Service Charge:	$18.00 per month	I
Plus an Energy Charge of:	$ 0.07618 per kWh	R

ADJUSTMENT CLAUSES

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

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

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within 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: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate

GS
General Service Rate

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
To general lighting and small power loads for secondary service.

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

RATE

Basic Service Charge:	$25.00 per month for single-phase service	I
	$40.00 per month for three-phase service	I
Plus an Energy Charge of:	$ 0.09245 per kWh	I

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

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Standard Rate

PS
Power Service Rate

APPLICABLE
In all territory served.

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

Service under this schedule will be limited to customers whose 12-month-average monthly minimum secondary loads exceed 50 kW and whose 12-month-average monthly maximum loads do not exceed 250 kW. Secondary or primary customers receiving service under P.S.C. of Ky. Electric No. 6, Fourth Revision of Original Sheet No. 15, Large Commercial Rate LC, and Fourth Revision of Original Sheet No. 25, Large Power Industrial Rate LP, as of February 6, 2009, with loads not meeting these criteria will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer.

RATE

	Secondary	Primary	
Basic Service Charge per month:	$90.00	$200.00	I
Plus an Energy Charge per kWh of:	$ 0.04071	$ 0.03964	I
Plus a Demand Charge per kW of:			
Summer Rate: (Five Billing Periods of May through September)	$17.33	$ 14.62	I
Winter Rate: (All other months)	$14.94	$ 12.33	I

Where the monthly billing demand is the greater of:

a) the maximum measured load in the current billing period but not less than 50 kW for secondary service or 25 kW for primary service, or

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

c) a minimum of 60% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate

PS
Power Service Rate

ADJUSTMENT CLAUSES

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

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

DETERMINATION OF MAXIMUM LOAD

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

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

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

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

DUE DATE OF BILL

Customer's payment will be due within 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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

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 of:	$ 0.04048	I
Plus a Maximum Load Charge per kW of:		
Peak Demand Period	$ 6.37	I
Intermediate Demand Period	$ 4.76	I
Base Demand Period	$ 4.26	I

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

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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, of the applicable kW charge.

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

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

RATING PERIODS

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

Summer peak months of May through September

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

All other months of October continuously through April

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

DUE DATE OF BILL

Customer's payment will be due within 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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Standard Rate **TODP** N

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:	$300.00
Plus an Energy Charge per kWh of:	$ 0.03823
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 5.04
Intermediate Demand Period	$ 3.69
Base Demand Period	$ 3.54

Where:

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

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

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

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

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

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

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

ADJUSTMENT CLAUSES

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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 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: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate

RTS
Retail Transmission Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for transmission service to any customer: (1) who has a 12-month- T
average monthly minimum demand exceeding 250 kVA; and (2) whose new or additional load T
receives any required approval of Company's transmission operator. T

RATE

Basic Service Charge per month:	$1,000.00	I
Plus an Energy Charge per kWh of:	$ 0.03712	I
Plus a Maximum Load Charge per kVA of:		
Peak Demand Period	$ 4.67	I
Intermediate Demand Period	$ 3.12	I
Base Demand Period	$ 2.87	I

Where:

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

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

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

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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 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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Standard Rate

FLS
Fluctuating Load Service

APPLICABLE
In all territory served.

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

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

BASE RATE

	Primary	Transmission	
Basic Service Charge per month:	$1,000.00	$1,000.00	I
Plus an Energy Charge per kWh of:	$ 0.03709	$ 0.03709	I
Plus a Maximum Load Charge per kVA of:			
Peak Demand Period	$ 3.02	$ 3.02	I
Intermediate Demand Period	$ 1.94	$ 1.94	I
Base Demand Period	$ 1.94	$ 1.17	I

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

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate

FLS
Fluctuating Load Service

ADJUSTMENT CLAUSES

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

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

DETERMINATION OF MAXIMUM LOAD

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

RATING PERIODS

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

Summer peak months of May through September

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

All other months of October continuously through April

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

DUE DATE OF BILL

Customer's payment will be due within 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: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

TERM OF CONTRACT

Unless terminated by mutual agreement, the initial term of contract for service shall be for a fixed term of five (5) years with successive one (1) year term renewal until canceled by either party giving at least one (1) year written notice to the other prior to the end of the initial term or the then current annual renewal period, as applicable.

PROTECTION OF SERVICE

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other undesirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 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 the CURTAILABLE SERVICE RIDERS CSR10 and CSR30. Company's right to interrupt under this provision is restricted to responses to unplanned outage or de-rates of LG&E and KU Energy LLC System ("LKE System") owned or purchased generation or when Automatic Reserve Sharing is invoked. LKE System, as used herein, shall consist of LG&E and KU. At customer's request, Company shall provide documentation of the need for interruption under this provision within sixty (60) days of the end of the applicable billing period.

LIABILITY

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

TERMS AND CONDITIONS

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

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	
High Pressure Sodium					
452	Cobra Head	16,000	0.181	$13.20	I
453	Cobra Head	28,500	0.294	15.52	
454	Cobra Head	50,000*	0.471	17.89	
455	Directional	16,000	0.181	$14.18	
456	Directional	50,000*	0.471	18.75	
457	Open Bottom	9,500	0.117	$11.18	
Metal Halide					
470	Directional	12,000	0.150	$13.17	
473	Directional	32,000	0.350	19.23	
476	Directional	107,800*	1.080	40.77	

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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate

LS
Lighting Service

Where the location of existing poles is not suitable or where there are no existing poles for mounting of lights, and customer requests service under these conditions, Company may furnish the requested facilities at an additional charge to be determined under the Excess Facilities Rider.
For wood poles installed prior to 3/1/2010, such charge will be in accordance with the rates listed T
on Sheet No, 36.1 of the Restricted Lighting Service Rate RLS Tariff. T

UNDERGROUND SERVICE

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

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Decorative Smooth	Monthly Charge Historic Fluted	T T
High Pressure Sodium						
412	Colonial, 4-Sided	5,800	0.083	$20.37		I
413	Colonial, 4-Sided	9,500	0.117	21.09		I
444	Colonial, 4-Sided	16,000	0.181	21.34		T/N
415	Acorn	5,800	0.083	$20.78		I
416	Acorn	9,500	0.117	23.23		I
445	Acorn	16,000	0.181	23.34		T/N
427	London	5,800	0.083		$36.24	I
429	London	9,500	0.117		37.13	I
431	Victorian	5,800	0.083		$33.90	I
433	Victorian	9,500	0.117		36.02	I
400	Dark Sky	4,000	0.060	$24.59		T/I
401	Dark Sky	9,500	0.117	25.63		T/I
					Westchester/Norfolk	
956	Victorian/London Bases				$ 3.67	I
423	Cobra Head	16,000	0.181	$27.13		I
424	Cobra Head	28,500	0.294	29.29		I
425	Cobra Head	50,000*	0.471	35.03		I

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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	
						T T
High Pressure Sodium						
439/420	Contemporary	16,000	0.181	$16.95	$30.77	T/I
440/421	Contemporary	28,500*	0.294	18.82	33.83	T/I
441/422	Contemporary	50,000*	0.471	22.98	39.52	T/I
Metal Halide						
479/480	Contemporary	12,000	0.150	$14.47	$24.53	I
481/482	Contemporary	32,000	0.350	21.06	31.10	I
483/484	Contemporary	107,800*	1.080	43.82	53.85	I

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

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
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

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

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

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

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

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 T
fixtures/poles composing a neighborhood lighting system or continuity is desired for a T
subdivision being developed in phases. Spot placement of restricted fixtures/poles is T
contingent on the restricted fixtures/poles being available from manufacturers. Spot replacement of restricted units will be made under the terms and conditions provided for under non-restricted Lighting Service Rate LS.

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

OVERHEAD SERVICE

Based on Customer's lighting choice, Company has furnished, installed, and maintained the lighting unit complete with lamp, fixture, photoelectric control, mast arm, and, if needed, up to 150 feet of conductor per fixture on existing wood poles (fixture only).

RATE

				Monthly Charge			
Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Fixture Only**	**Fixture & Wood Pole**	**Fixture & Orn. Pole**	
Mercury Vapor							
252	Cobra/Open Bottom	8,000	0.210	$ 9.59			I
203	Cobra Head	13,000	0.298	11.28			T/I
204	Cobra Head	25,000	0.462	13.91			I
209	Cobra Head	60,000	1.180	28.51			
207	Directional	25,000	0.462	$16.00			
210	Directional	60,000	1.180	29.74			
201	Open Bottom	4,000	0.100	$ 8.38			
Metal Halide							
471	Directional	12,000	0.150		$15.51	N/A	I
474/475	Directional	32,000	0.350		21.59	29.26	I
477	Directional	107,800	1.080		44.04	N/A	I

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DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate **RLS**

Restricted Lighting Service

OVERHEAD SERVICE (continued)

RATE T

Rate Code		Monthly Charge	
			T
Wood Pole			
958	Installed Before 3/1/2010	$11.64	I
900	Installed Before 7/1/2004	2.12	I

UNDERGROUND SERVICE

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

RATE

				Monthly Charge		
Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Fixture Only	Decorative Smooth	
High Pressure Sodium						
275	Cobra/Contemporary	16,000	0.181		$25.62	I
266	Cobra/Contemporary	28,500	0.294		28.15	
267	Cobra Contemporary	50,000	0.471		32.33	
276	Coach/Acorn	5,800	0.083		$14.59	
274	Coach/Acorn	9,500	0.117		17.70	
277	Coach/Acorn	16,000	0.181		22.80	
279/278	Contemporary	120,000	1.000	$42.65	$74.69	
417	Acorn, Bronze	9,500	0.117		$24.38	
419	Acorn, Bronze	16,000	0.180		25.50	
280	Victorian	5,800	0.083	$19.95		
281	Victorian	9,500	0.117	20.95		
282	London	5,800	0.083	$20.11		
283	London	9,500	0.117	21.43		

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate **RLS**
Restricted Lighting Service

UNDERGROUND SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth	
High Pressure Sodium						
426	London	5,800	0.083		$34.20	I
428	London	9,500	0.117		35.10	
430	Victorian	5,800	0.083		33.21	
432	Victorian	9,500	0.117		35.34	
Victorian/London Bases						
950	Old Town				$ 3.57	
951	Chesapeake				3.84	
Poles						
901	10” Smooth Pole				11.13	
902	10” Fluted Pole				13.28	
Mercury Vapor						
318	Cobra Head	8,000	0.210		$17.93	
314	Cobra Head	13,000	0.298		19.77	
315	Cobra Head	25,000	0.462		23.63	
347	Cobra (State of KY Pole)	25,000	0.462	$23.62		
206	Coach	4,000	0.100		$12.82	
208	Coach	8,000	0.210		14.66	
Incandescent						
349	Continental Jr.	1,500	0.102		$ 9.29	
348	Continental Jr.	6,000	0.447		13.51	

Where Customer’s location required the installation of additional facilities, Company may have furnished the requested facilities at an additional charge per month to be determined under the Excess Facilities Rider.

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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

DETERMINATION OF ENERGY CONSUMPTION

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

ADJUSTMENT CLAUSES

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

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

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

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

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

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

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

Standard Rate

LE
Lighting Energy Service

APPLICABLE
In all territory served.

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

RATE
$0.06661 per kWh I

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

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

DUE DATE OF BILL
Customer's payment will be due within 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: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate

TE
Traffic Energy Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

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

RATE

Basic Service Charge:	$4.00 per delivery per month	I
Plus an Energy Charge of:	$0.07659 per kWh	I

ADJUSTMENT CLAUSES

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

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

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

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

DATE OF ISSUE: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Traffic Energy Service

CONDITIONS OF SERVICE

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

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

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

TERMS AND CONDITIONS

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

Standard Rate

CTAC
Cable Television Attachment Charges

APPLICABLE
In all territory served.

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

ATTACHMENT CHARGE
$9.11 per year for each attachment to pole.

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

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

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

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

Standard Rate **CTAC**

Cable Television Attachment Charges

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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

Standard Rate **CTAC**
Cable Television Attachment Charges

4. **MAINTENANCE OF ATTACHMENTS**
Customer shall, at its own expense, make and maintain said attachments in safe condition and in thorough repair, and in a manner suitable to Company and so as not to conflict with the use of said poles by Company, or by other parties, firms, corporations, governmental units, etc., using said poles, pursuant to any license or permit by Company, or interfere with the working use of facilities thereon or which may, from time to time, be placed thereon. Customer shall promptly at any time, at its own expense, upon written notice from Company, relocate, replace or renew its facilities placed on said poles, and transfer them to substituted poles, or perform any other work in connection with said facilities that may be required by Company but in no case longer than 30 day after date of written request. In cases of emergency, however, Company may arrange to relocate, replace or renew the facilities placed on said poles by Customer, transfer them to substituted poles or perform any other work in connection with said facilities that may be required in the maintenance, replacement, removal or relocation of said poles, the facilities thereon or which may be placed thereon, or for the service needs of Company, or its other licensees, and Customer shall, on demand, reimburse Company for the expense thereby incurred.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Standard Rate **CTAC**
Cable Television Attachment Charges

11. ATTACHMENT REMOVAL AND NOTICES

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

12. FORBIDDEN USE OF POLES

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

13. NON-COMPLIANCE

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

14. WAIVERS

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

15. USE OF COMPANY'S FACILITIES BY OTHERS

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

16. ASSIGNMENT

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

17. PROPERTY RIGHTS

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

18. FAILURE TO PROCEED

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

19. TERMINATION

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

20. SECURITY

Customer shall furnish bond for the purposes hereinafter specified as follows:

(a) during the period of Customer's initial installation of its facilities and at the time of any expansion involving more than seventy-five (75) poles, a bond in the amount of $2,000 for each 100 poles (or fraction thereof) to which Customer intends to attach its facilities;
(b) following the satisfactory completion of Customer's initial installation, the amount of bond shall be reduced to $1,000 for each 100 poles (or fraction thereof);
(c) after Customer has been a customer of Company pursuant to the Agreement and is not in default thereunder for a period of three years, the bond shall be reduced to $500 for each 100 poles (or fraction thereof).
(d) such bond shall contain the provision that it shall not be terminated prior to six (6) months after receipt by Company of written notice of the desire of the bonding or insurance company to terminate such bond. This six (6) months' termination clause may be waived by Company if an acceptable replacement bond is received before the six (6) months has ended. Upon receipt of such termination notice, Company shall request Customer to immediately remove its cables, wires and all other facilities from all poles of Company. If Customer should fail to complete the removal of all of its facilities from the poles of Company within thirty (30) days after receipt of such request from Company, then Company shall have the right to remove them at the cost and expense of Customer and without being liable for any damage to Customer's wires, cables, fixtures or appurtenances. Such bond shall guarantee the payment of any sums which may become due to Company for rentals, inspections or work performed for the benefit of Customer under the Agreement, including the removal of attachments upon termination of the Agreement by any of its provisions.

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

21. NOTICES

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

22. ADJUSTMENTS

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

23. BINDING EFFECT

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

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

METER DATA PROCESSING CHARGE

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate Rider **CSR10**

Curtailable Service Rider 10

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to customers served under applicable power schedules who
contract for not less than 1,000 kVA individually. The aggregate service under CSR10 and T
CSR30 for Louisville Gas and Electric Company is limited to 100 MVA in addition to the T
contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric Company as
of August 1, 2010.

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification
by Company. Requests for curtailment shall not exceed one hundred (100) hours per year nor T
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 T
shall give no less than ten (10) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year. 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. T
> During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. 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.
>
> 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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate Rider **CSR10**

Curtailable Service Rider 10

T

RATE T

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

Transmission Voltage Service	$ 5.40 per kVA of Curtailable Billing Demand
Primary Voltage Service	$ 5.50 per kVA of Curtailable Billing Demand
Non-Compliance Charge of:	$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. T

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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.

Standard Rate Rider **CSR30**

Curtailable Service Rider 30

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to customers served under applicable power schedules who
contract for not less than 1,000 kVA individually. The aggregate service under CSR10 and T
CSR30 for Louisville Gas and Electric Company is limited to 100 MVA in addition to the T
contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric Company as
of August 1, 2010.

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification
by Company. Requests for curtailment shall not exceed one hundred (100) hours per year nor T
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 T
shall give no less than thirty (30) minutes notice when either requesting or canceling a
curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year. T
Curtailable load and compliance with a request for curtailment shall be measured in one of the T
following ways:

> Option A -- Customer may contract for a given amount of firm demand in kVA. T
> During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. 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.
>
> Non-compliance for each requested physical curtailment shall be the measured positive value determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) the Customer's maximum demand during such curtailment.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate Rider **CSR30**

Curtailable Service Rider 30

T

RATE

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

Transmission Voltage Service	$ 4.30 per kVA of Curtailable Billing Demand
Primary Voltage Service	$ 4.40 per kVA of Curtailable Billing Demand
Non-Compliance Charge of:	$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

T

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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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. 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 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 month of June, July, August and September, during the hours 9:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours),	$0.04041 per kWh.
2. For winter billing months of December, January and February, during the hours 7:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours),	$0.03536 per kWh.
3. During all other hours (off-peak hours)	$0.03327 per kWh.

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

RATE B: NON-TIME-DIFFERENTIATED RATE

For all kWh purchased by Company,	$0.03443 per kWh

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: June 30, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: April 17, 1999

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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

Standard Rate Rider **LQF**

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

AVAILABILITY

In all territory served.

APPLICABILITY OF SERVICE

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

RATES FOR PURCHASES FROM QUALIFYING FACILITIES

Energy Component Payments

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

Capacity Component Payments

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

Determination of CAP_i

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

1. System demand is less than or equal to Company's capacity:
   $D_{\mathbf{1}} \leq C_{\mathbf{LG\&E}}$; $CAP_{\mathbf{i}} = 0$

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:

   $C_{\mathbf{LG\&E}} < D_{\mathbf{i}} \leq [C_{\mathbf{LG\&E}} + C_{\mathbf{QF}}]$; $CAP_{\mathbf{i}} = C_{\mathbf{M}}$

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

   $D_{\mathbf{i}} > [C_{\mathbf{LG\&E}} + C_{\mathbf{QF}}]$; $CAP_{\mathbf{i}} = C_{\mathbf{QF}}$

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: November 26, 2014

DATE EFFECTIVE: November 1, 1995

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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

Standard Rate Rider

NMS
Net Metering Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

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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. T If Customer takes service under 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 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.

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

NET METERING SERVICE INTERCONNECTION GUIDELINES T

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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NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

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4. A net metering generator interconnected to Company's three-phase, three-wire primary distribution lines, shall appear as a phase-to-phase connection to Company's primary distribution line.
5. A net metering generator interconnected to Company's three-phase, four-wire primary distribution lines, shall appear as an effectively grounded source to Company's primary distribution line.
6. A net metering generator will not be connected to an area or spot network.
7. There are no identified violations of the applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems".
8. Company will not be required to construct any facilities on its own system to accommodate the net metering generator.

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

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

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

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

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

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Standard Rate Rider **NMS**

Net Metering Service

CONDITIONS OF INTERCONNECTION

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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.

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DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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. 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 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

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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. T

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.

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TERMS AND CONDITIONS

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

LEVEL 1

Application for Interconnection and Net Metering

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

Submit this Application to:

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

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

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

Customer Name: ________________________ Account Number: ____________

Customer Address: ________________________________

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

Project Contact Person: ________________________________

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

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

____

Energy Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Inverter Manufacturer and Model #: ________________________

Inverter Power Rating: ______________ Inverter Voltage Rating: ______________

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

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

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

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

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

Expected Start-up Date: ________________________

LEVEL 2

Application for Interconnection and Net Metering

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

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

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

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

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

Customer Name: ______________________ Account Number: ______________

Customer Address: ______________________________________

Project Contact Person: ______________________________________

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

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

____

Total Generating Capacity of Generating Facility: ______________________________

Type of Generator: ____Inverter-Based ____Synchronous ____Induction

Power Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

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

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

Customer Signature: ______________________________ Date: ______________

Standard Rate Rider

EF
Excess Facilities

APPLICABILITY

In all territory served.

AVAILABILITY OF SERVICE

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

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	1.32%

(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	0.54%

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.

Standard Rate Rider **RC**

Redundant Capacity

APPLICABLE

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

AVAILABILITY

Available to customers requesting the reservation of capacity on Company's facilities which are shared by other customers when Company has, and is willing, to reserve such capacity. Such facilities represent a redundant delivery to provide electric service to Customer's facility in the event that an emergency or unusual occurrence renders Customer's principal delivery unavailable for providing service. Where Customer desires to split a load between multiple meters on multiple feeds and contract for Redundant Capacity on those feeds, service is contingent on the practicality of metering to measure any transferred load to the redundant feed.

RATE:

Capacity Reservation Charge

Secondary Distribution	$1.43 per kW/kVA per Month	I
Primary Distribution	$1.26 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 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 (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.

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DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate Rider

SS
Supplemental or Standby Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

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

RATE

	Secondary	Primary	Transmission	
Contract Demand per kW/kVA per Month:	$13.57	$12.30	$10.83	I/I/R

CONTRACT DEMAND

Contract Demand is defined as the number of kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) mutually agreed upon as representing Customer's maximum service requirements and contracted for by Customer; provided, however, if such number of kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) is exceeded by a recorded demand, such recorded demand shall become the new contract demand commencing with the month in which recorded and continuing for the remaining term of the contract or until superseded by a higher recorded demand.

MINIMUM CHARGE

Company will bill Customer monthly for all of the charges under Customer's applicable rate schedule, including, but not limited to, the applicable basic service charge, energy charges, and adjustment clauses. In addition to those charges, Company will bill Customer monthly a demand charge that is the greater of: (1) the Customer's total demand charge calculated under the applicable rate schedule; or (2) the demand charge calculated using the applicable demand rate shown above applied to the Contract Demand. If Customer's applicable rate schedule does not contain a demand charge, the Customer's monthly demand charge will be the demand charge calculated using the applicable demand rate shown above applied to the Contract Demand. T

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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. T T T

SPECIAL TERMS AND CONDITIONS

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

2) In the event Customer's use of service is intermittent or subject to violent fluctuations, Company will require Customer to install and maintain at Customer's own expense suitable equipment to satisfactorily limit such intermittence or fluctuations.

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

TERM OF CONTRACT

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

TERMS AND CONDITIONS

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

Standard Rate Rider

IL
Rider for Intermittent Loads

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company, in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other desirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 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.

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 and/or Seasonal Electric Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider is available at the option of the Company where: T

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. where Customer has need for temporary intermittent use of Company facilities and Company T
   has facilities it is willing to provide Customer for installation and operational testing of T
   Customer's equipment. T

This service is available for not less than one (1) month (approximately 30 days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes. Where this service is provided under 2 or 3, above, the Company will determine the T
term of service, which shall not exceed one (1) year. 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:

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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Standard Rate Rider **SGE**

Small Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.

b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one MWh of green power.

RATE

Voluntary monthly contributions of any amount in $5.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $5.00 increments (e.g., $5.00, $10.00, $15.00, or more per month) An eligible Customer may participate in Company's "Green Energy Program" by making a request to Company's Call Center or through Company's website enrollment form and may withdraw at any time through a request to Company's Call Center. Funds provided by Customer to Company are not refundable.

b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.

c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

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DATE EFFECTIVE: June 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00467 dated February 22, 2010**

Standard Rate Rider **LGE**

Large Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.

b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one MWh of green power.

RATE

Voluntary monthly contributions of any amount in $13.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $13.00 increments (e.g., $13.00, $26.00, $39.00, or more per month). An eligible customer may participate in Company's "Green Energy Program" by making a request to the Company and may withdraw at any time through a request to the Company. Funds provided by Customer to Company are not refundable.

b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.

c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

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DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate Rider **EDR**

Economic Development Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available as a rider to customers to be served or being served under Company's Standard Rate Schedules TODS, TODP, and RTS to encourage Brownfield Development or Economic Development (as defined herein). Service under EDR is conditional on approval of a special contract for such service filed with and approved by the Public Service Commission of Kentucky. T

RATE

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

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

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

TERMS AND CONDITIONS

Brownfield Development

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

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 (or kW as is appropriate); and

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DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Economic Development

2) existing customers contracting for a minimum monthly billing load of 1,000 kVA (or kW as is appropriate) above their Existing Base Load, to be determined as follows:
   i. Company and the existing customer will determine Customer's Existing Base Load by averaging Customer's previous three years' monthly billing loads, subject to any mutually agreed upon adjustments thereto.
   ii. Company and the existing customer must agree upon the Existing Base Load, which shall be an explicit term of the special contract submitted to the Commission for approval before the customer can take service under EDR. Once the Existing Base Load's value is thus established, it will not be subject to variation or eligible for service under EDR.
   iii. This provision is not intended to reduce or diminish in any way EDR service already being provided to all or a portion of a customer's Existing Base Load. Such EDR service would continue under the terms of the contract already existing between the Company and the customer concerning the affected portion of the customer's Existing Base Load.

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

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. T

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. T

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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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Adjustment Clause **FAC**

Fuel Adjustment Clause

APPLICABLE.

In all territory service.

AVAILABILITY OF SERVICE

This schedule is mandatory to all electric rate schedules.

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

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

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

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

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

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

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

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 April 2012 and the base fuel factor is $0.02725 per kWh.

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

(8) Pursuant to the Public Service Commission's Orders in Case No. 2012-00553 dated May 17, 2013, and May 29, 2013, the Fuel Adjustment Clause will become effective with bills rendered on and after the first billing cycle for July 2013, which begins June 26, 2013.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: With Bills Rendered On and After
June 26, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of Orders of the Public
Service Commission in Case No. 2012-00553
dated May 17, 2013 and May 29, 2013**

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 Service Rate RTOD-Energy, Residential Time of Day Demand Service Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Service Rate RTS. 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:

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 T
Fire Department, and General Service customer classes is defined as the weighted T
average price per kWh of expected billings under the energy charges contained in
the RS, RTOD-Energy, VFD, and GS rate schedules in the upcoming twelve-month T
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, and T
RTS) is defined as the weighted average price per kWh represented by the T
composite of the expected billings under the respective demand and energy charges in the upcoming twelve-month period, after deducting the variable costs included in the energy charges.

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

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

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

DSMI = DSM INCENTIVE

For all Energy Impact Programs except Direct Load Control, the DSM incentive amount
shall be computed by multiplying the net resource savings expected from the approved T

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State Regulation and Rates
Louisville, Kentucky

programs that are to be installed during the upcoming twelve-month period times fifteen T
(15) percent, not to exceed five (5) percent of program expenditures. Net resource T
savings are defined as program benefits less utility program costs and participant costs T
where program benefits will be calculated on the basis of the present value of Company's T
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, T
Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day T
Demand Service Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, T
General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate
TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Service Rate T
RTS shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month T
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.

T

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State Regulation and Rates
Louisville, Kentucky

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. T

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:

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

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 (30) days prior to the effective period for billing. Each filing shall include the following information as applicable:

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

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

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State Regulation and Rates
Louisville, Kentucky

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. T

Residential Load Management / Demand Conservation

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

Residential Conservation / Home Energy Performance Program

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

Residential Low Income Weatherization Program (WeCare)

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

Smart Energy Profile

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

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

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

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

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

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

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DATE EFFECTIVE: May 31, 2012

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Residential HVAC Diagnostics and Tune Up Program

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

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

Customer Education and Public Information

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

Dealer Referral Network

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

Commercial Customer Program Participation Incentives:

The following Demand Side Management programs are available to commercial customers receiving service from the Company on the GS, PS, TODS, TODP, and RTS Standard Electric Rate Schedules. T

Commercial Load Management / Demand Conservation

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

Commercial Conservation (Energy Audits) / Commercial Incentives

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

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

Commercial HVAC Diagnostics and Tune Up Program

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

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

Customer Education and Public Information

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

Dealer Referral Network

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

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.

Current Program Incentive Structures

Residential Load Management / Demand Conservation

Switch Option:

- $5/month bill credit for June, July, August, & September per air conditioning unit or heat pump on single family home.
- $2/month bill credit for June, July, August, & September per electric water heater (40 gallon minimum) or swimming pool pump on single family home.
- If new customer registers by May 31, 2014, then a $25 gift card per air-conditioning unit, heat pump, water-heater (40 gallon minimum) and/or swimming pool pump switch installed.
  - Customers in a tenant landlord relationship will receive the entire $25 new customer incentive.

Multi-family Option:

- Tenant - $2/month bill credit per customer for June, July, August, & September per air conditioning unit, heat pump, or water heater (40 gallon minimum).
- Entire Complex Enrollment – Property owner receives $2/month incentive per air conditioning or heat pump switch to the premise owner for June, July, August, & September.
- If new customer registers by May 31, 2014, then a $25 gift card per air-conditioning unit or heat pump installed, where:
  - Customers in a tenant/property owner relationship where the entire complex participates, the property owner will receive a $25 bonus incentive per air conditioning unit, heat pump, or water heater (40 gallon minimum).
  - Customers in a tenant landlord relationship where only a portion of the complex participates, the tenant will receive a $25 gift card new customer incentive.

Residential Refrigerator Removal Program

The program provides $50 per working refrigerator or freezer.

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DATE EFFECTIVE: December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Commercial Load Management / Demand Conservation

Switch Option

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

Customer Equipment Interface Option

The Company will offer a Load Management / Demand Response program tailored to a commercial customer's ability to reduce load. Program participants must commit to a minimum of 50 kW demand reduction per control event. The Company will continue to enroll program participants until 10MW curtailable load is achieved.

- $25 per kW for verified load reduction during June, July, August, & September.
- The customer will have access to at least hourly load data for every month of the year which they remain enrolled in the program.
- Additional customer charges may be incurred for metering equipment necessary for this program at costs under other tariffs.

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Residential Service Rate RS, 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		T T T T
DSM Cost Recovery Component (DCR)	$ 0.00192	per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00144	per kWh	
DSM Incentive (DSMI)	$ 0.00009	per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00106	per kWh	
DSM Balance Adjustment (DBA)	$ 0.00092	per kWh	
Total DSMRC for Rates RS, RTOD-Energy, RTOD-Demand, and VFD	$ 0.00543	per kWh	T

General Service Rate GS*	Energy Charge		T
DSM Cost Recovery Component (DCR)	$ 0.00089	per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00199	per kWh	
DSM Incentive (DSMI)	$ 0.00004	per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00004	per kWh	
DSM Balance Adjustment (DBA)	$ 0.00007	per kWh	
Total DSMRC for Rate GS	$ 0.00303	per kWh	

Power Service Rate PS*	Energy Charge		T
DSM Cost Recovery Component (DCR)	$ 0.00033	per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00066	per kWh	
DSM Incentive (DSMI)	$ 0.00002	per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00011	per kWh	
DSM Balance Adjustment (DBA)	$ 0.00027	per kWh	
Total DSMRC for Rate PS	$ 0.00139	per kWh	

Time-of-Day Secondary Service Rate TODS*, Time-of-Day Primary Service Rate TODP*, and Retail Transmission Service Rate RTS*	Energy Charge		T T T
DSM Cost Recovery Component (DCR)	$ 0.00025	per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00046	per kWh	
DSM Incentive (DSMI)	$ 0.00001	per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00002	per kWh	
DSM Balance Adjustment (DBA)	$ 0.00002	per kWh	
Total DSMRC for Rates TODS, and TODP	$ 0.00076	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. T T

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Adjustment Clause

ECR
Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

Group 1: Rate Schedules RS; RTOD-Energy; RTOD-Demand; VFD; LS; RLS; LE; and TE. T
Group 2: Rate Schedules GS; PS; TODS; TODP; RTS; and FLS. T

RATE

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

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

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

DEFINITIONS

1) For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – EAS + BR
   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/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

DEFINITIONS (continued) T

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

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

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

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

Adjustment Clause **FF**

Franchise Fee Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

DEFINITIONS

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

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

RATE

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

BILLING

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

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.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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

Adjustment Clause

ST
School Tax

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

RATE

The utility gross receipts license tax authorized under state law.

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DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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

Adjustment Clause **HEA**

Home Energy Assistance Program

APPLICABLE

In all territory served.

AVAILABILITY

To all residential customers.

RATE

$0.25 per meter per month.

BILLING

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

SERVICE PERIOD

The Home Energy Assistance charge will be applied to all residential electric bills rendered during the billing cycles commencing January 1, 2013 until the effective date of new base rates, or as otherwise directed by the Public Service Commission. The HEA program is approved through September 30, 2015. 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.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

Customer Bill of Rights

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

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

COMPANY TERMS AND CONDITIONS.

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

COMPANY AS A FEDERAL CONTRACTOR T

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.

ASSIGNMENT

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

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

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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.

TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

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

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

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

TRANSFER OF APPLICATION

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

CONTRACTED DEMANDS

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

OPTIONAL RATES

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

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

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

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DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

TERMS AND CONDITIONS

Customer Responsibilities

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

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

CUSTOMER’S EQUIPMENT AND INSTALLATION

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

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

OWNER'S CONSENT TO OCCUPY

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

ACCESS TO PREMISES AND EQUIPMENT

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

PROTECTION OF COMPANY'S PROPERTY

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

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DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

Customer Responsibilities

POWER FACTOR

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

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

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

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

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

LIABILITY

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

NOTICE TO COMPANY OF CHANGES IN CUSTOMER’S LOAD

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

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State Regulation and Rates
Louisville, Kentucky

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TERMS AND CONDITIONS

Customer Responsibilities

PERMITS

Customer shall obtain or cause to be obtained all permits, easements, or certificates, except street permits, necessary to give Company or its agents access to Customer's premises and equipment and to enable its service to be connected therewith. In case Customer is not the owner of the premises or of intervening property between the premises and Company's distribution lines, 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 the customer.

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Company Responsibilities

METERING

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

POINT OF DELIVERY OF ELECTRICITY

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

EXTENSION OF SERVICE

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

COMPANY'S EQUIPMENT AND INSTALLATION

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

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

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State Regulation and Rates
Louisville, Kentucky

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

TERMS AND CONDITIONS

Character of Service

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

SECONDARY VOLTAGES

Residential Service -

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

Non-Residential Service -

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

PRIMARY VOLTAGES

According to location, 2400/4160Y volts, 7200/12,470Y volts, 13,800 volts, or 34,500 volts.

TRANSMISSION VOLTAGES

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

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

RESTRICTIONS

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

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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.

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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 his 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 Rate RS when measured through the residential meter subject to the conditions set forth below:

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

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

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

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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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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

BILLING

METER READINGS AND BILLS

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 meters at least quarterly, except that customer-read meters shall be read at least once during the calendar year.

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

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

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

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

Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within 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

TERMS AND CONDITIONS

BILLING

assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice. There will be no adverse credit impact on the customer’s payment and credit record, including credit scoring, both internally and externally, and the account will not be considered delinquent for any purpose if the Company receives the customer’s payment within fifteen days after the date on which the Company issues the customer’s bill.

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

READING OF SEPARATE METERS NOT COMBINED

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

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.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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2012-00222 dated December 20, 2012

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 then taking service under such a rate schedule, Company will not change Customer’s rate assignment; it will remain Customer’s responsibility to choose between optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1.

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

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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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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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 the customer's meter reading and billing records, Company may contact Customer to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether 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 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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DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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 four (4) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.

RESIDENTIAL

1) Residential customers are those customers served under Residential Service Rate RS - T
Sheet No. 5, Residential Time-of-Day Energy Service Rate RTOD-Energy – Sheet No. 6, and T
Residential Time-of-Day Demand Service Rate RTOD-Demand – Sheet No. 7. T
2) The deposit for a residential customer is in the amount of $160.00, which is calculated in I
accordance with 807 KAR5:006, Section 8(1)(d)(2). For combination gas and electric
customers, the total deposit will be $260.00. I
3) Company shall retain Customer’s deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.
4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated, at Customer’s request, and based on Customer’s actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation. T

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DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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. T T T T

GENERAL SERVICE

1) General service customers are those customers served under General Service Rate GS, Sheet No. 10. T
2) The deposit for a general service customer is in the amount of $240.00, which is calculated in accordance with 807 KAR5:006, 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 energy usage is no more than 300 kWh per month. I
3) Company shall retain Customer's deposit as long as Customer remains on service.
4) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than ten percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential or general service, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 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 percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Budget Payment Plan

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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.

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

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format

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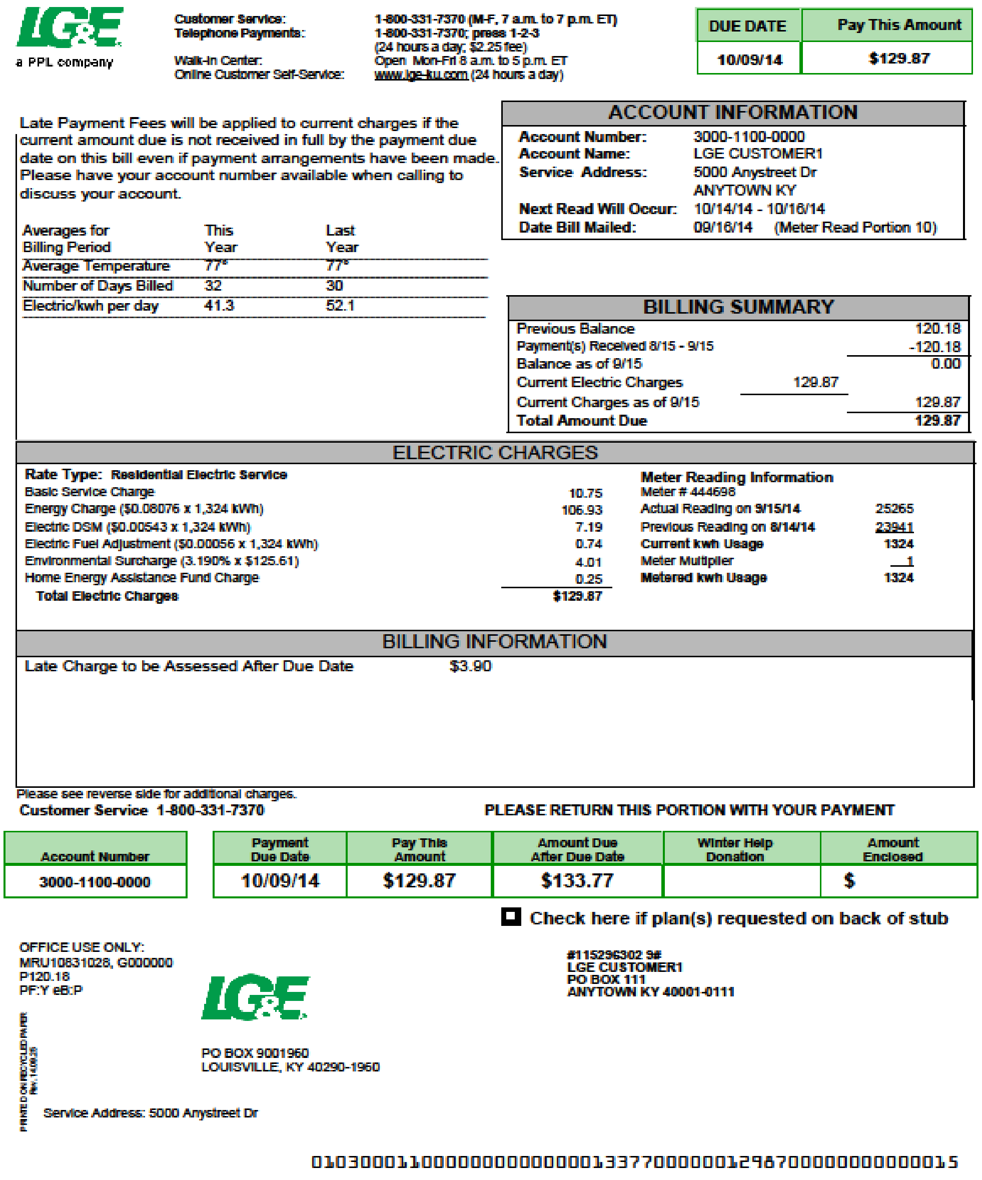

a PPL company

Customer Service:	**1-800-331-7370 (M-F, 7 a.m. to 7 p.m. ET)**
Telephone Payments:	**1-800-331-7370; press 1-2-3** (24 hours a day; $2.25 fee)
Walk-In Center:	Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service:	www.lge-ku.com (24 hours a day)

DUE DATE	Pay This Amount
10/09/14	**$129.87**

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

Averages for Billing Period	This Year	Last Year
Average Temperature	77°	77°
Number of Days Billed	32	30
Electric/kwh per day	41.3	52.1

ACCOUNT INFORMATION

Account Number:	3000-1100-0000
Account Name:	LGE CUSTOMER1
Service Address:	5000 Anystreet Dr ANYTOWN KY
Next Read Will Occur:	10/14/14 - 10/16/14
Date Bill Mailed:	09/16/14 (Meter Read Portion 10)

BILLING SUMMARY

Previous Balance		120.18
Payment(s) Received 8/15 - 9/15		-120.18
Balance as of 9/15		0.00
Current Electric Charges	129.87	
Current Charges as of 9/15		129.87
Total Amount Due		**129.87**

ELECTRIC CHARGES

Rate Type: Residential Electric Service

Basic Service Charge	10.75
Energy Charge ($0.08076 x 1,324 kWh)	106.93
Electric DSM ($0.00543 x 1,324 kWh)	7.19
Electric Fuel Adjustment ($0.00056 x 1,324 kWh)	0.74
Environmental Surcharge (3.190% x $125.61)	4.01
Home Energy Assistance Fund Charge	0.25
Total Electric Charges	**$129.87**

Meter Reading Information

Meter # 444698

Actual Reading on 9/15/14	25265
Previous Reading on 8/14/14	23941
Current kwh Usage	1324
Meter Multiplier	1
Metered kwh Usage	1324

BILLING INFORMATION

Late Charge to be Assessed After Due Date $3.90

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number
3000-1100-0000

Payment Due Date	Pay This Amount	Amount Due After Due Date	Winter Help Donation	Amount Enclosed
10/09/14	**$129.87**	**$133.77**		**$**

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

OFFICE USE ONLY:
MRU10831028, G000000
P120.18
PF:Y eB:P

PO BOX 9001960
LOUISVILLE, KY 40290-1960

#115296302 9#
LGE CUSTOMER1
PO BOX 111
ANYTOWN KY 40001-0111

PRINTED ON RECYCLED PAPER

Service Address: 5000 Anystreet Dr

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format

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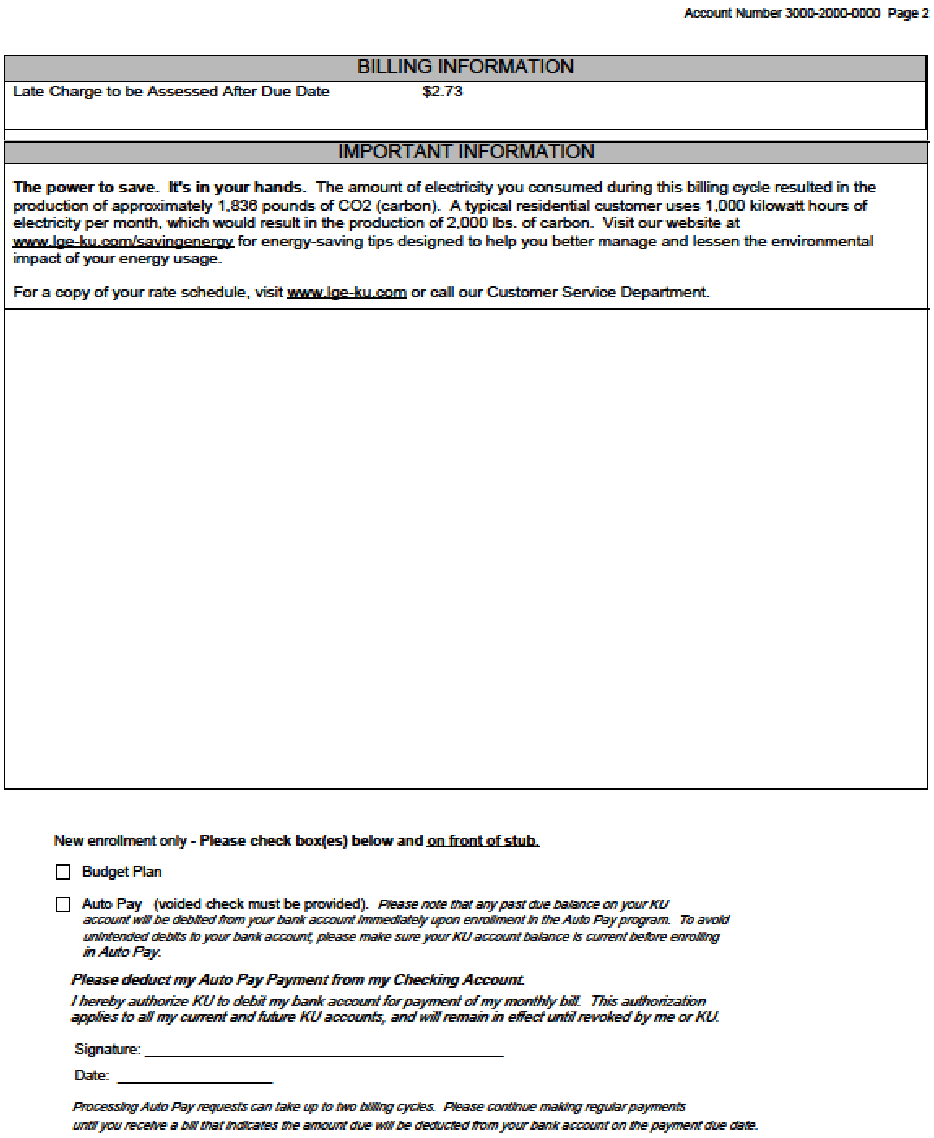

Account Number 3000-2000-0000 Page 2

BILLING INFORMATION	
Late Charge to be Assessed After Due Date	$2.73

IMPORTANT INFORMATION

The power to save. It's in your hands. The amount of electricity you consumed during this billing cycle resulted in the production of approximately 1,836 pounds of CO2 (carbon). A typical residential customer uses 1,000 kilowatt hours of electricity per month, which would result in the production of 2,000 lbs. of carbon. Visit our website at <u>www.lge-ku.com/savingenergy</u> for energy-saving tips designed to help you better manage and lessen the environmental impact of your energy usage.

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

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

☐ Budget Plan

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

Please deduct my Auto Pay Payment from my Checking Account.

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

Signature: ______________________________

Date: ________________

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format

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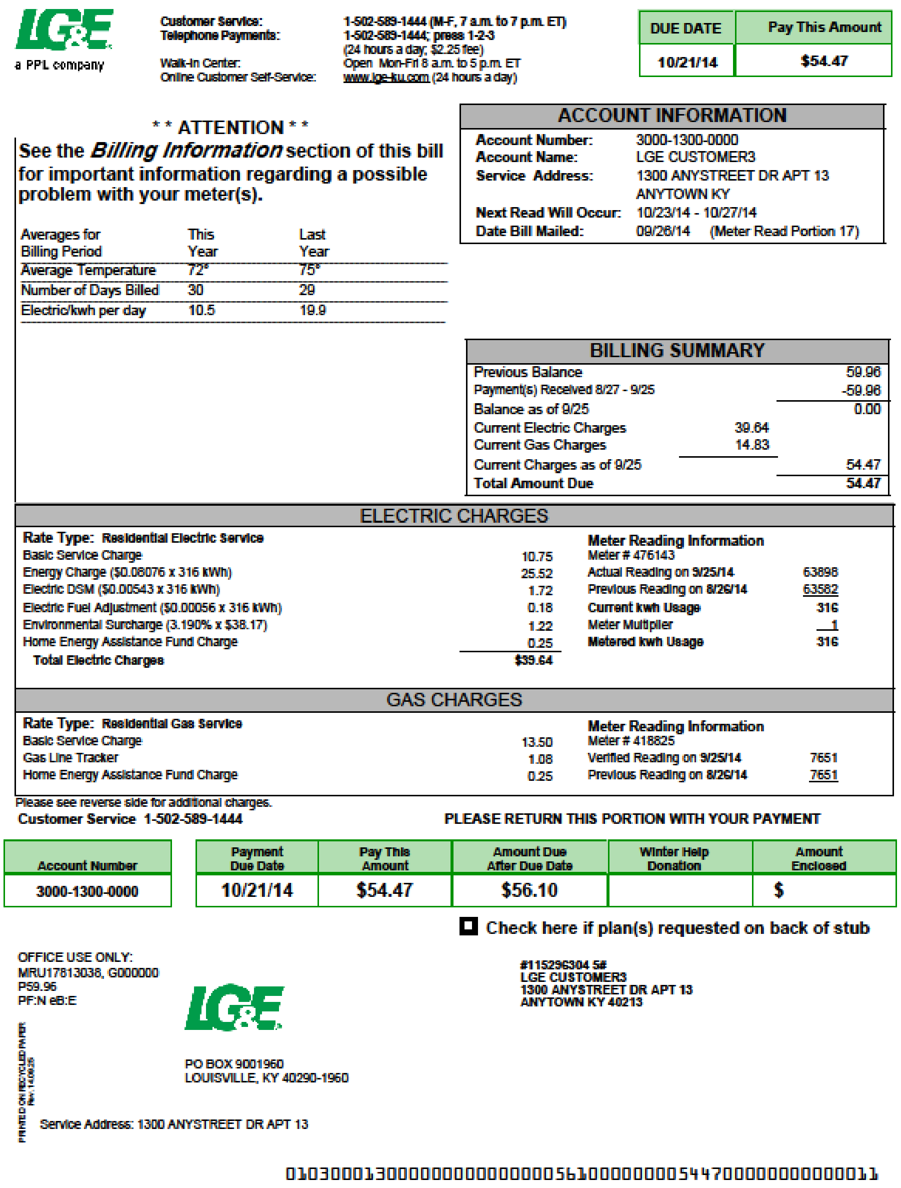

a PPL company

Customer Service: 1-502-589-1444 (M-F, 7 a.m. to 7 p.m. ET)
Telephone Payments: 1-502-589-1444; press 1-2-3 (24 hours a day; $2.25 fee)
Walk-In Center: Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service: www.lge-ku.com (24 hours a day)

DUE DATE	Pay This Amount
10/21/14	$54.47

* * ATTENTION * *

See the ***Billing Information*** section of this bill for important information regarding a possible problem with your meter(s).

Averages for Billing Period	This Year	Last Year
Average Temperature	72°	75°
Number of Days Billed	30	29
Electric/kwh per day	10.5	19.9

ACCOUNT INFORMATION

Account Number:	3000-1300-0000
Account Name:	LGE CUSTOMER3
Service Address:	1300 ANYSTREET DR APT 13 ANYTOWN KY
Next Read Will Occur:	10/23/14 - 10/27/14
Date Bill Mailed:	09/26/14 (Meter Read Portion 17)

BILLING SUMMARY

Previous Balance		59.96
Payment(s) Received 8/27 - 9/25		-59.96
Balance as of 9/25		0.00
Current Electric Charges	39.64	
Current Gas Charges	14.83	
Current Charges as of 9/25		54.47
Total Amount Due		**54.47**

ELECTRIC CHARGES

Rate Type: Residential Electric Service

Basic Service Charge	10.75
Energy Charge ($0.08076 x 316 kWh)	25.52
Electric DSM ($0.00543 x 316 kWh)	1.72
Electric Fuel Adjustment ($0.00056 x 316 kWh)	0.18
Environmental Surcharge (3.190% x $38.17)	1.22
Home Energy Assistance Fund Charge	0.25
Total Electric Charges	**$39.64**

Meter Reading Information
Meter # 476143

Actual Reading on 9/25/14	63898
Previous Reading on 8/26/14	63582
Current kwh Usage	**316**
Meter Multiplier	1
Metered kwh Usage	**316**

GAS CHARGES

Rate Type: Residential Gas Service

Basic Service Charge	13.50
Gas Line Tracker	1.08
Home Energy Assistance Fund Charge	0.25

Meter Reading Information
Meter # 418825

Verified Reading on 9/25/14	7651
Previous Reading on 8/26/14	7651

Please see reverse side for additional charges.

Customer Service 1-502-589-1444

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number	Payment Due Date	Pay This Amount	Amount Due After Due Date	Winter Help Donation	Amount Enclosed
3000-1300-0000	10/21/14	$54.47	$56.10		$

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

OFFICE USE ONLY:
MRU17813038, G000000
P59.96
PF:N eB:E

PO BOX 9001960
LOUISVILLE, KY 40290-1960

#115296304 5#
LGE CUSTOMER3
1300 ANYSTREET DR APT 13
ANYTOWN KY 40213

PRINTED ON RECYCLED PAPER
Rev. 140826

Service Address: 1300 ANYSTREET DR APT 13

01030001300000000000000056100000000544700000000000011

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format

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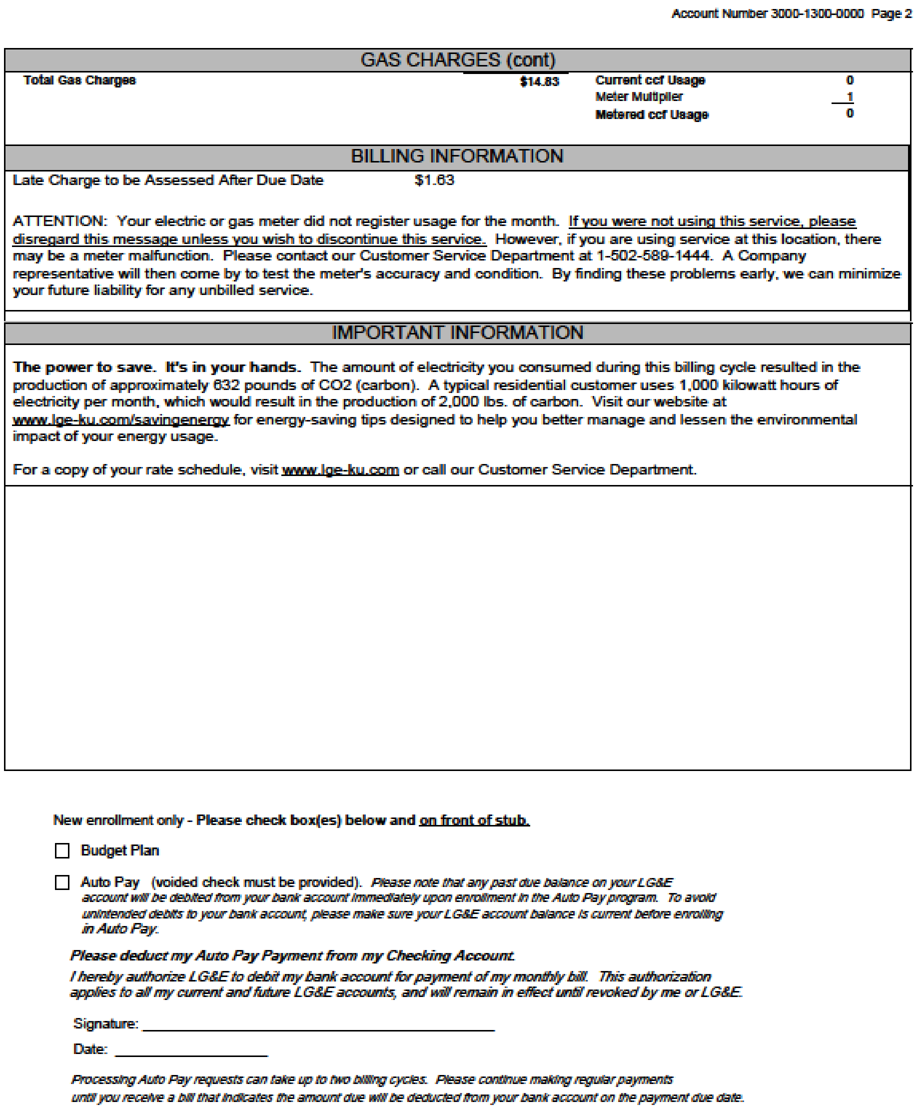

Account Number 3000-1300-0000 Page 2

GAS CHARGES (cont)

Total Gas Charges	**$14.83**	**Current ccf Usage**	**0**
		Meter Multiplier	**1**
		Metered ccf Usage	**0**

BILLING INFORMATION

Late Charge to be Assessed After Due Date $1.63

ATTENTION: Your electric or gas meter did not register usage for the month. If you were not using this service, please disregard this message unless you wish to discontinue this service. However, if you are using service at this location, there may be a meter malfunction. Please contact our Customer Service Department at 1-502-589-1444. A Company representative will then come by to test the meter's accuracy and condition. By finding these problems early, we can minimize your future liability for any unbilled service.

IMPORTANT INFORMATION

The power to save. It's in your hands. The amount of electricity you consumed during this billing cycle resulted in the production of approximately 632 pounds of CO2 (carbon). A typical residential customer uses 1,000 kilowatt hours of electricity per month, which would result in the production of 2,000 lbs. of carbon. Visit our website at www.lge-ku.com/savingenergy for energy-saving tips designed to help you better manage and lessen the environmental impact of your energy usage.

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

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

☐ Budget Plan

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

Please deduct my Auto Pay Payment from my Checking Account.

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

Signature: ______________________________

Date: ________________

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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. T T

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

C. When 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. T T T T

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. T

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 T T T T T

DATE OF ISSUE: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Discontinuance of Service

15(1)(f). Final Bills transferred following a lapse in service will not be subject to disconnection T
unless: (1) such service was provided pursuant to a fraudulent application submitted by T
Customer; (2) Customer and Company have entered into a contractual agreement T
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 T
Company for service previously supplied at the same or other premises until payment of such
indebtedness shall have been made. Service will not be supplied where the Applicant is a T
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 T
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 T
delivered, including, but not limited to, electronic mail), of state and federal programs which T
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 T
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 T
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

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TERMS AND CONDITIONS

Discontinuance of Service

use or theft of service. Company shall not be required to restore service until Customer has complied with all rules of Company and regulations of the Commission and Company has been reimbursed for the estimated amount of the service rendered and the cost to Company incurred by reason of the fraudulent use. 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. T T

TERMS AND CONDITIONS

Line Extension Plan

A. AVAILABILITY

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

B. DEFINITIONS

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

C. GENERAL

1) All extensions of service will be made through the use of overhead facilities except as provided in these rules.
2) Customer requesting service which requires an extension(s) shall furnish to Company, at no cost, properly executed easement(s) for right-of-way across Customer's property to be served.
3) Customer requesting extension of service into a subdivision, subject to the jurisdiction of a public commission, board, committee, or other agency with authority to zone or otherwise regulate land use in the area and require a plat (or Plan) of the subdivision, Customer shall furnish, at no cost, Company with the plat (or plan) showing street and lot locations with utility easement and required restrictions. Plats (or plans) supplied shall have received final approval of the regulating body and recorded in the office of the appropriate County Court Clerk when required. Should no regulating body exist for the area into which service is to be extended, Customer shall furnish Company the required easement.
4) The title to all extensions, rights-of way, permits, and easements shall be and remain with Company.

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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. T
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) The Company shall not be obligated to extend its lines in cases where such extensions, in the good judgment of Company, would be infeasible, impractical, or contrary to good engineering or operating practice, unless otherwise ordered by Commission.

D. NORMAL LINE EXTENSIONS

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

E. OTHER LINE EXTENSIONS

1) In accordance with 807 KAR 5:041, Section 11(2), Company shall provide to Customer requesting permanent service a line extension in excess of 1,000 feet per customer but Company may require the total cost of the footage in excess of 1,000 feet per customer, based on the average cost per foot of the total extension, be deposited with Company by Customer.
2) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension for each additional customer connected during that year directly to the original extension for which the deposit was made.
3) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension less the length of the lateral or extension for each additional customer connected during that year by a lateral or extension to the original extension for which the deposit was made.
4) 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

Line Extension Plan

E. OTHER LINE EXTENSIONS (continued)

5) Where Customer requires poly-phase service or transformer capacity above 25kVA per customer and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in OTHER LINE EXTENSIONS ¶ 1 above. T

F. OVERHEAD LINE EXTENSIONS FOR SUBDIVISIONS

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

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. Company shall provide, at no cost, a line extension of up to 300 feet to Customer requesting permanent service for a mobile home. T
2) 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.
3) 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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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND 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. T T
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 including the service and with the exception of Company's meter. T
6) The normal point of delivery shall be at a junction device at the corner of the lot nearest Company's facilities. Customer shall bring Customer's service line to a point within 1 1/2 feet of the junction device with a sufficient length of service conductor left coiled above grade for completion of installation and connection by Company.
7) In consideration of Customer's underground service, Company shall credit any amounts due under the contract for each service at the rate of $50.00 or Company's average estimated installed cost for an overhead service whichever is greater.
8) Unit charges, where specified herein, are determined from Company's estimate of Company's average unit cost of such construction and the estimated cost differential between underground and overhead distribution systems in representative residential subdivisions.
9) Three phase primary required to supply either individual loads or the local distribution system may be overhead unless Customer chooses underground construction and deposits with Company a non-refundable deposit for the cost differential.

Individual Premises

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS

Individual Premises (continued)

2) In cases other than those specified in 1) above, where Customer requests and Company agrees to supply underground service to an individual premise, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.

Medium Density Subdivisions

1) A medium density residential subdivision is defined as containing ten or more lots for the construction of new residential buildings each designed for less than five (5)-family occupancy.
2) Customer shall provide any required trenching and backfilling or at Company's discretion be required to deposit with Company a non-refundable amount determined by a unit charge of $6.94 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.
3) The Customer may be required to advance to the Company the Company's full estimated cost of construction of an underground electric distribution extension. Where Customer is required to provide trenching and backfilling, advance will be the Company's full estimate cost of construction. Where Customer is required to deposit with the Company a non-refundable advance in place of trenching and backfilling, advance will be determined by a unit charge of $21.17 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.
4) Each year for ten (10) years Company shall refund to Customer an amount determined as follows:
   a. Where customer is required to provide trenching and backfilling, a refund of $5,000 for each customer connected during that year.
   b. Where customer is required to provide a non-refundable advance, 500 times the difference in the unit charge advance amount in 3) and the non-refundable unit charge advance in 2) for each customer connected during that year.
5) In no case shall the refunds provided for herein exceed the amounts deposited less any non-refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends.

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.

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS

High Density Subdivisions (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 for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.
3) The Customer may be required to advance to the Company the Company's full estimated cost of construction of an underground electric distribution extension.
   i. Company shall refund to Customer any amounts due when permanent service is provided by Company to twenty (20%) percent of the family units in Customer's project.
   ii. In no case shall the refunds provided for herein exceed the amounts deposited less any non-refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends.

Other Underground Subdivisions

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

I. SPECIAL CASES

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

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State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PURPOSE

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

ENERGY CURTAILMENT PROCEDURE

PRIORITY LEVELS

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

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

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

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

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

D. "Fire Stations", which shall be limited to facilities housing mobile fire-fighting apparatus.

E. "Communication Services", which shall be limited to essential uses required for telephone, telegraph, television, radio and newspaper operations, and operation of state and local emergency services.

F. "Water and Sewage Services", which shall be limited to essential uses required for the supply of water to a community, flood pumping and sewage disposal.

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 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.

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.

Special Contracts
Electric

Summary of Proposed Charges Under Electric Special Contracts

Customer 1	Demand Charge:	
	Winter Rate	$12.77 per kW per month
	Summer Rate	$15.09 per kW per month
	Energy Charge	$0.03910 per kWh
Customer 2	Demand Charge:	$10.40 per kW of billing demand per month
	Energy Charge	$0.03872 per kWh

P.S.C. Gas No. 10
Canceling P.S.C. Gas No. 9

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

NATURAL GAS SERVICE

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

PUBLIC SERVICE COMMISSION

OF KENTUCKY

DATE OF ISSUE: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Standard Gas Rate Schedules – Terms and Conditions

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State Regulation and Rates
Louisville, Kentucky

GENERAL INDEX
Standard Gas Rate Schedules – Terms and Conditions

SECTION 4 – Terms and Conditions

DATE OF ISSUE: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate **RGS**

Residential Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

The term "residential" customers shall include customers using gas in a single-family residential
dwelling or unit for space-heating, air conditioning, cooking, water-heating, incineration,
refrigeration, laundry drying, lighting, incidental heating, personal vehicle fueling, or other T
domestic purposes, including the use of gas in standby electric generation in domestic
applications. If an additional separate point of delivery is requested by a residential customer
to provide gas for use in standby electric generation, customer shall be served under Standard
Rate DGGS. Company shall not be obligated to install an additional service to a residential T
customer for the purpose of the customer installing equipment for either electric standby T
generation or personal vehicle fueling. T

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

RATE

Basic Service Charge:	$19.00 per delivery point per month	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.21325	R
Gas Supply Cost Component	$ 0.56128	
Total Gas Charge Per 100 Cubic Feet	$ 0.77453	R

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

ADJUSTMENT CLAUSES

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

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within 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.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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2012-00222 dated December 20, 2012

Standard Rate

VFD
Volunteer Fire Department Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load. If an additional separate point of delivery is requested by a volunteer fire department qualifying for aid under KRS 95A.262 to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS.

DEFINITION

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

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

RATE

Basic Service Charge:	$19.00 per delivery point per month	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.21325	
Gas Supply Cost Component	$ 0.56128	R
Total Gas Charge Per 100 Cubic Feet	$ 0.77453	R

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

ADJUSTMENT CLAUSES

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

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

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State Regulation and Rates
Louisville, Kentucky

Standard Rate **VFD**

Volunteer Fire Department Service

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.

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Standard Rate **CGS**

Firm Commercial Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

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

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

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

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

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

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State Regulation and Rates
Louisville, Kentucky

Standard Rate **CGS**

Firm Commercial Gas Service

RATE

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 40.00 per delivery point per month	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$180.00 per delivery point per month	I

Plus a Charge Per 100 Cubic Feet:

Distribution Cost Component	$ 0.23445	I
Gas Supply Cost Component	0.56128	
Total Charge Per 100 Cubic Feet	$ 0.79573	I

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

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

ADJUSTMENT CLAUSES

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

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate

CGS
Firm Commercial Gas Service

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.

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State Regulation and Rates
Louisville, Kentucky

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Standard Rate

IGS
Firm Industrial Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

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

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

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

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

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State Regulation and Rates
Louisville, Kentucky

Standard Rate

IGS
Firm Industrial Gas Service

RATE

Basic Service Charge:		
If all of the customer's meters have a capacity < 5000 cf/hr:	$ 40.00 per delivery point per month	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$180.00 per delivery point per month	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.24305	I
Gas Supply Cost Component	$ 0.56128	
Total Charge Per 100 Cubic Feet	$ 0.80433	I

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

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

ADJUSTMENT CLAUSES

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

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

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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.

Standard Rate

AAGS
As-Available Gas Service

APPLICABLE
In all territory served.

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

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

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

COMPANY NOT OBLIGATED TO CONTINUE SERVICE
Company shall have the right to discontinue the supply of natural gas wholly or in part for such period or periods as, in the sole judgment of Company, may be necessary or advisable to enable it to supply the full gas requirements of its customers served under higher priority rate schedules. Nothing herein shall prevent Company from expanding its obligations under such other rate schedules. Company may decline to accept any additional contracts for service hereunder.

CONTRACT TERM
Customers served under Rate AAGS shall enter a written contract with Company more fully described in the Special Terms and Conditions of this rate schedule. The minimum contract term for service hereunder shall be for a period of at least one (1) year and shall commence on

CONTRACT TERM (continued)

November 1 and be effective through the following October 31, and year to year thereafter, unless terminated by either Company or Customer upon prior written notice on or before the April 30 preceding the October 31 termination date.

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

RATE

Basic Service Charge:
$400.00 per delivery point per month I

Plus a Charge Per Mcf

Distribution Cost Component	$ 0.8285	I
Gas Supply Cost Component	$ 5.6128	
Total Charge Per Mcf	$ 6.4413	I

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

ADJUSTMENT CLAUSES

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

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

PENALTY FOR FAILURE TO INTERRUPT

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

PENALTY FOR FAILURE TO INTERRUPT (continued)

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

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Customer shall be charged a per Mcf penalty charge applicable to any unauthorized takes of gas during the period of interruption (excluding Pilot Light Requirements where applicable) equal to $15.00 plus the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the period of interruption that falls into each monthly billing cycle, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the period of interruption that falls into each monthly billing cycle. Such penalty for failure to interrupt shall be in addition to any other charges under this rate schedule for such unauthorized usage by Customer that occurs following the conclusion of the eighteen- (18-) hour notice of interruption by Company to Customer.

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

SPECIAL TERMS AND CONDITIONS

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

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

Standard Rate **AAGS**

As-Available Gas Service

SPECIAL TERMS AND CONDITIONS (continued)

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

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

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

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

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

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

9. Any Customer contracting for service hereunder, other than a Customer transferring from either Rate G-6 or Rate G-7 as stipulated above, may be required, in the sole discretion of Company, either prior to electing service hereunder or at any time thereafter, to have appropriate remote metering devices. The remote metering devices allow Company to monitor the Customer's usage and determine compliance with notice of interruption of
service hereunder. The Customer shall reimburse Company for the cost of the remote T
metering equipment, for any modifications to Company facilities, and for the replacement of T
any existing meters required in order to facilitate the functioning of the remote metering. T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

SPECIAL TERMS AND CONDITIONS (continued)

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

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

DUE DATE OF BILL

Customer's payment will be due within 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.

TERMS AND CONDITIONS

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to existing commercial and industrial customers who consume at least 50 Mcf each day at each individual Delivery Point during each month of the twenty-four (24) months prior to the March 31 service request date, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's Pipeline Transporter, and have requested Company to utilize its system to transport, by displacement, such customer-owned gas to Customer's place of utilization. Customers electing to transfer from another service shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rate schedule shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30.

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

Customers using natural gas for vehicular fueling of internal combustion engines must also elect service under Rider NGV. T
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Any such transportation service hereunder shall be conditioned on Company being granted a reduction in billing demands by its Pipeline Transporter corresponding to the Customer's applicable transportation quantities.

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

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

CHARACTER OF SERVICE

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

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

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

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

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

RATE

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

Administrative Charge: $550.00 per Delivery Point per month I

Distribution Charge Per Mcf: $0.4431 I

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rate FT. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rate FT in order to recover from (or refund to) transferring sales customers any under- or over-

RATE (continued)

collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly Gas Supply Clause filings.

For customers electing service under Rate FT effective November 1, 2013,
the Gas Cost True-Up Charge shall be:

$(0.0584) per Mcf for Bills Rendered On and After November 1, 2014

For customers electing service under Rate FT effective November 1, 2014,
the Gas Cost True-Up Charge shall be:

$0.5669 per Mcf for Bills Rendered On and After November 1, 2014

Minimum Daily Threshold Requirement and Charge: When Customer's daily usage falls below the Minimum Daily Threshold Requirement, Customer will be charged a Minimum Daily Threshold Charge equal to the difference between the Minimum Daily Threshold Requirement and the Customer's actual consumption in Mcf for that day multiplied by the Distribution Charge hereunder. The Minimum Daily Threshold Requirement is equal to the minimum daily volume of 50 Mcf. Such Minimum Daily Threshold Charge shall be accumulated for each day of the applicable month and billed during that month in accordance with the following formula:

Minimum Daily Threshold Charge =

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: November 1, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00348 dated October 27, 2014

Standard Rate

FT
Firm Transportation Service (Transportation Only)

RATE (continued)

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

ADJUSTMENT CLAUSES

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

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

DUE DATE OF BILL

Customer's payment will be due within 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

IMBALANCES

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

$$\text{Imbalance} = \text{Metered Usage} - \text{Delivered Volume}$$

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

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

The term “day” or “daily” shall mean the period of time corresponding to the gas day as T
observed by the Pipeline Transporter as adjusted for local time. T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from Customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either (a) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred. T

The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

When Total Net Negative Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount: T T
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred. T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows: T

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤5%	100%
>5% to ≤10%	110%
>10% to ≤15%	120%
>15% to ≤20%	130%
>20%	140%

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

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

VARIATIONS IN MMBTU CONTENT

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

UTILIZATION CHARGE FOR DAILY IMBALANCES

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

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UTILIZATION CHARGE FOR DAILY IMBALANCES (continued)

Daily Demand Charge:	$0.1576 per Mcf
Daily Storage Charge:	$0.1833
Utilization Charge for Daily Imbalances:	$0.3409 per Mcf

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

These charges are in addition to any other charges set forth herein. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed ±5% of the delivered volume unless an OFO has been issued. If an OFO has been issued, the Utilization Charge for Daily Imbalances shall apply to daily imbalances which exceed 0% for customers in violation of the OFO directive, either “condition (a)” or “condition (b)” as applicable and further described below under “Operational Flow Orders”. Customers not in violation of the OFO directive, either “condition (a)” or “condition (b)” as applicable, will continue to be assessed the Utilization Charge for Daily Imbalances on volumes which exceed the 5% daily tolerance. Company shall not have an obligation to provide balancing service for any volumes of gas hereunder.

OPERATIONAL FLOW ORDERS

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

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

Upon issuance of an OFO, Company will direct Customer to comply with one of the following conditions: (a) Customer must take delivery of an amount of natural gas from Company that is no more than the daily amount being delivered by the Pipeline Transporter to Company for Customer; or (b) Customer must take delivery of an amount of natural gas from Company that T

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

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OPERATIONAL FLOW ORDERS (continued)

is no less than the daily amount being delivered by the Pipeline Transporter to Company for Customer. Customer shall respond to an OFO by either adjusting its deliveries to Company's system or its consumption at its facility. All volumes taken by Customer in excess of volumes delivered by Pipeline Transporter to Company for Customer in violation of the above “condition (a)” OFO shall constitute an unauthorized receipt by Customer from Company. All volumes taken by Customer less than volumes delivered by Pipeline Transporter to Company for Customer in violation of the above “condition (b)” OFO shall constitute an unauthorized delivery by Customer to Company. Unauthorized receipts or deliveries during the effectiveness of an OFO shall be subject to an OFO Charge per Mcf for each Mcf of unauthorized receipts or deliveries, as applicable. Customer shall be subject to the OFO Charge on the day for which the OFO was violated, plus the applicable UCDI charges and any other charges under this rate schedule for such unauthorized receipts or deliveries that occur.

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

The OFO Charge per Mcf shall be equal to $15.00 plus the higher of the following: either (a) the daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS for the day on which the OFO was violated, or (b) the daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS for the day on which the OFO was violated. Such OFO Charge shall be in addition to any other charges under this rate schedule.Company will not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of an OFO. Payment of OFO Charges hereunder shall not be considered an exclusive remedy for failure to comply with the OFO, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

OPTIONAL SALES AND PURCHASE TRANSACTION

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

RETURN TO FIRM SALES SERVICE

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

REMOTE METERING

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

The Customer shall reimburse Company for the cost of this remote metering equipment and the T
cost of its installation, including any modifications to Company facilities and the replacement of T
any existing meters required in order to facilitate the functioning of the remote metering. T

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

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

SPECIAL TERMS AND CONDITIONS

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

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

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Standard Rate **FT**

Firm Transportation Service (Transportation Only)

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SPECIAL TERMS AND CONDITIONS (continued)

system for Customer's account. Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by Customer to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from Customer daily nominations, or changes thereto, that are made after the daily deadline for Transporter, shall be provided by Customer to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from Customer daily nominations, or changes thereto, that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company. Company will not be obligated to utilize its underground storage capacity for purposes of this service.

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

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

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

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

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

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DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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SPECIAL TERMS AND CONDITIONS (continued)

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

TERMS AND CONDITIONS

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

Standard Rate

DGGS
Distributed Generation Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

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

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

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

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

CHARACTER OF SERVICE

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

Standard Rate

DGGS
Distributed Generation Gas Service

RATE

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

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 40.00 per delivery point per month	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$180.00 per delivery point per month	I

Demand Charge per 100 cubic feet of Monthly Billing Demand:	$1.1685	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$0.03454	I
Gas Supply Cost Component	0.56128	
Total Charge Per 100 Cubic Feet	$0.59582	I

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

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

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

ADJUSTMENT CLAUSES

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

Gas Line Tracker	Sheet No. 84
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate

DGGS
Distributed Generation Gas Service

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.

SPECIAL TERMS AND CONDITIONS

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

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

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

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

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

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

TERMS AND CONDITIONS

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

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 5:022, Section 8(3)(a)1, and Section 8(3)(b)1, the Customer will be charged $90.00 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 gas service when discontinued for non-payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.

Customers under Gas Rates RGS, CGS, IGS, and AAGS may request and be granted T
temporary suspension of gas service In the event of such temporary suspension, Company will
make a charge of $28.00 to cover disconnection and reconnection of gas service, such charge
to be made before reconnection is effected. If both gas and electric services are reconnected
at the same time, the total charge for both services shall be $28.00. Customers taking service T
under Riders TS-2, GMPS, and EF shall not be eligible for such temporary suspension of T
service T

INSPECTION CHARGE

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

T

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State Regulation and Rates
Louisville, Kentucky

Special Charges

CHARGE FOR TEMPORARY AND SHORT TERM SERVICE T

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

ADDITIONAL TRIP CHARGE

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate Rider **TS-2**

Gas Transportation Service/Firm Balancing Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to existing commercial and industrial customers served under Rates AAGS, CGS, and IGS who consume at least 15,000 Mcf annually at each individual Delivery Point during the two (2) years ending with the March 31 service request date.

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

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

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

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

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

Standard Rate Rider TS-2
Gas Transportation Service/Firm Balancing Service

CHARACTER OF SERVICE

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

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

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

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

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

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

RATE

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

Administrative Charge: $550.00 per Delivery Point per month I

	CGS	IGS	AAGS	
Distribution Charge Per Mcf	$2.3445	$2.4305	$0.8285	I
Pipeline Supplier’s Demand Component	0.7792	0.7792	0.7792	
Total	$3.1237	$3.2097	$1.6077	I

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State Regulation and Rates
Louisville, Kentucky

RATE (continued)

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

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

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

For customers electing service under Rider TS-2 effective November 1, 2013,
the Gas Cost True-Up Charge shall be:

$(0.0584) per Mcf for Bills Rendered On and After November 1, 2014

For customers electing service under Rider TS-2 effective November 1, 2014,
the Gas Cost True-Up Charge shall be:

$0.5669 per Mcf for Bills Rendered On and After November 1, 2014

Minimum Annual Threshold Requirement and Charge: When Customer’s annual usage falls below the Minimum Annual Threshold Requirement, Customer will be charged a Minimum Annual Threshold Charge equal to the difference between the Minimum Annual Threshold Requirement of 15,000 Mcf and the Customer’s actual consumption in Mcf during each Contract Year which difference shall be multiplied by the peak period Distribution Charge of the applicable sales rate schedule. Such Minimum Annual Threshold Charge shall be billed during the month following the close of the Contract Year in accordance with the following formula

Minimum Annual Threshold Charge =

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

Standard Rate Rider **TS-2**

Gas Transportation Service/Firm Balancing Service

RATE (continued)

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

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

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

Optional Monthly Telemetry Charge: $300.00 per Delivery Point per month

T

REMOTE METERING

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

At the time that the Customer executes a contract for service hereunder, Customer shall elect
to either (1) pay for the cost of this remote metering equipment and the cost of its installation in T
an up-front lump sum payment, or (2) pay the Optional Monthly Telemetry Charge specified
herein. Under either option, Customer shall reimburse Company for the cost of any T
modifications to Company facilities and the replacement of any existing meters required in T
order to facilitate the functioning of the remote metering. T

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

The Customer shall be responsible for providing the necessary and adequate electric and T
telephone service to provide remote metering by October 1 of the year that Customer's service ↓
under Rider TS-2 becomes effective. Electric and telephone services installed for this
equipment shall conform to Company's specifications. The Customer shall be responsible for
maintaining the necessary and adequate electric and telephone service to provide remote
metering.

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

SPECIAL TERMS AND CONDITIONS T

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

   Customer may appoint only one TS-2 Pool Manager for a given period. If Customer elects to change its TS-2 Pool Manager, Customer shall notify Company and execute and return the required documentation of its election to change its TS-2 Pool Manager at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective. Except as provided for in Rider TS-2, no customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year. In appointing a TS-2 Pool Manager, Customer acknowledges that it has appointed the designated TS-2 Pool Manager to act as its limited agent in the performance of certain stated functions and to assume certain stated responsibilities with regard to transportation under Rider TS-2, including the requesting and receiving of information, the scheduling of gas flows, and all related duties. Customer will continue to be responsible for any and all costs, fees, and other liabilities as the result of the actions or inactions of TS-2 Pool Manager as its limited agent. Customer shall indemnify, defend, and hold Company harmless from any costs (including, but not limited to, reasonable attorney fees), expenses, losses, or liabilities, incurred (a) as a result of Company's performance when relying upon the authority of the TS-2 Pool Manager, (b) as a result of Company's reliance upon Customer's representation that it has express authority to appoint said TS-2 Pool Manager as its limited agent, and (c) due to the Customer's or TS-2 Pool Manager's failure to strictly comply with the provisions of Rider TS-2 or Rider PS-TS-2. T

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

SPECIAL TERMS AND CONDITIONS (continued) T

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

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

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

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

TERMS AND CONDITIONS

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

Standard Rate Rider **GMPS**

Gas Meter Pulse Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

CHARACTER OF SERVICE

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

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

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

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

The Company will provide the pulse generator(s). Customer Installed Equipment is any equipment or wiring installed by the Customer, or someone other than Company acting on behalf of Customer, and could include, but would not be limited to, any device such as a data concentrator, totalizer, programmable logic controller, remote terminal unit, or similar equipment used for the purpose of collecting the pulse data. Customer is responsible for installation of wiring to the pulse generator(s) and is responsible for providing the wetting voltage necessary to generate electrical pulses, as well as all dielectric isolation fittings, surge protection and electrical barriers. The wetting voltage must be a regulated DC voltage of 30 volts or less and

CHARACTER OF SERVICE (continued)

10 mA or less, or as otherwise determined by the Company. If Customer Installed Equipment is located within fifteen (15) feet of any gas pipeline flanges, gas regulators, or gas pressure relief devices; or if gas meters are installed in an enclosed space, then Customer Installed Equipment must be installed in accordance with National Electrical Code Class 1 Division 2 requirements.

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

RATE

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

For Customers Served Under Rate Schedule FT or Rider TS-2:

Monthly Charge:	$ 7.17

For Customers Not Served Under Rate Schedule FT or Rider TS-2:

Monthly Charge:	$24.34

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

SPECIAL TERMS AND CONDITIONS

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

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State Regulation and Rates
Louisville, Kentucky

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2012-00222 dated December 20, 2012

SPECIAL TERMS AND CONDITIONS (continued)

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

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

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

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

6. Either party may terminate service under this Rate Schedule upon sixty (60) days prior written notice. Customer shall immediately disconnect and remove Customer's Installed Equipment upon termination, or shall request Company to do so at Customer's sole cost.

SPECIAL TERMS AND CONDITIONS (continued)

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

TERMS AND CONDITIONS

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

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

Pooling Service – Rider-TS-2

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to TS-2 Pool Managers.

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

For the purpose of this rider, a “TS-2 Pool Manager” is defined as an entity which has been appointed by a customer or group of customers served under Rider TS-2 to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties. A customer served under Rider TS-2 must join a Rider PS-TS-2 pool managed by a third-party Pool Manager.

RATE

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

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

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

CHARACTER OF SERVICE

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

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

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

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State Regulation and Rates
Louisville, Kentucky

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

Pooling Service – Rider TS-2

ACTION ALERTS

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

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

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

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

The Action Alert Charge per Mcf shall be equal to $5.00 plus the higher of the following: either T (a) the daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS for the day on which the AA was violated, or (b) the daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS for the day on which the AA was violated. Such Action Alert Charge shall be in addition to any other charges under this rider.

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

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Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

IMBALANCES T

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

$$\text{Imbalance} = \text{Metered Usage} - \text{Delivered Volumes}$$

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

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

The term "day" or "daily" shall mean the period of time corresponding to the gas day as T
observed by the Pipeline Transporter as adjusted for local time. T

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

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

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from TS-2 Pool Manager at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either T (a) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly negative imbalance percentage to be applied as follows:

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State Regulation and Rates
Louisville, Kentucky

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

CASH-OUT PROVISION FOR MONTHLY IMBALANCES (continued)

T

When Total Net Negative Balance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), TS-2 Pool Manager shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly imbalance percentage to be applied as follows:

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When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤5%	100%
>5% to ≤10%	110%
>10% to ≤15%	120%
>15% to ≤20%	130%
>20%	140%

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State Regulation and Rates
Louisville, Kentucky

CASH-OUT PROVISION FOR MONTHLY IMBALANCES (continued) T

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

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

VARIATIONS IN MMBTU CONTENT

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

NOMINATIONS AND NOMINATED VOLUME

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

At least ten (10) days prior to the beginning of each calendar month, TS-2 Pool Manager shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for the Pool Manager's TS-2 Pool.
Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by TS-2 Pool Manager to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from TS-2 Pool Manager daily nominations or changes thereto that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company.

T

NOMINATIONS AND NOMINATED VOLUME (continued) T

Such volumes nominated by TS-2 Pool Manager shall include an allowance for Company's system average lost and unaccounted for gas ("LAUFG") expressed as a percentage and based on historical levels. Effective November 1, 2013, such LAUFG percentage is 3.56%. Such LAUFG percentage shall be revised annually each November 1 with notice provided to TS-2 Pool Manager at least thirty (30) days prior to such November 1. The volumes delivered by the TS-2 Pool Manager to Company for redelivery to Customers in the TS-2 Pool will be increased by TS-2 Pool Manager to cover the effective LAUFG percentage. For example, if the Customers in a TS-2 Pool require 325 Mcf on a given day, and the LAUFG% is 5.0%, then the Mcf nominated shall be 342 Mcf [325 / (1 - 0.05)]. The 342 Mcf shall be converted to MMBtu using a standard conversion factor as may be specified by Company from time to time. Such amount does not include any retention by the Pipeline Transporter. The volume nominated by the TS-2 Pool Manager to cover LAUFG shall not be considered in determining whether or not the TS-2 Pool Manager has exceeded the Pool Maximum Daily Quantity ("PMDQ") for the TS-2 Pool.

SUPPLIER CODE OF CONDUCT

Each PS-TS-2 Pool Manager participating in the Company's transportation program under Rider PS-TS-2 must:

1. communicate to participating Customers in clear, understandable terms the Customer's rights and responsibilities. This communication must include (a) the PS-TS-2 Pool Manager's customer service address and local or toll-free telephone number; and (b) a statement describing the PS-TS-2 Pool Manager's dispute resolution procedures;
2. provide in writing pricing and payment terms that are clearly defined and understandable and that inform consumers whether the price that the Customer will pay is inclusive or exclusive of applicable taxes, and Company approved tariff riders and surcharges;
3. refrain from engaging in communications or promotional practices which are fraudulent, deceptive, or misleading; T
4. deliver gas to the Company on a firm basis on behalf of the Customers enrolled in the PS-TS-2 Pool Manager's pool in accordance with the requirements of the PS-TS-2 Pool Management Agreement;

T

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

SUPPLIER CODE OF CONDUCT T

5. establish and maintain a credit-worthy financial position that enables PS-TS-2 Pool Manager to indemnify the Company and the Customers for costs incurred as a result of any failure by the PS-TS-2 Pool Manager to deliver gas in accordance with the requirements of Rider PS-TS-2 and to assure payment of any applicable charges for any such failure;
6. refrain from requesting customer-specific billing, payment, and usage history without first having received the Customer's written approval allowing PS-TS-2 Pool Manager to access such information.

Failure to fulfill any of these obligations shall be considered a violation of the Supplier Code of Conduct.

If the PS-TS-2 Pool Manager fails to comply with the Supplier Code of Conduct, the Company will have the discretion to temporarily suspend or terminate such PS-TS-2 Pool Manager from further participation in the transportation program under Rider PS-TS-2. If service to the PS-TS-2 Pool Manager is suspended or terminated, Customer(s) in the PS-TS-2 Pool Manager's Pool will be returned to sales service under the applicable rate schedule (CGS, IGS, or AAGS) until said Customer(s) join another PS-TS-2 Pool Manager's Pool. If the Company seeks to suspend or terminate service to a PS-TS-2 Pool Manager, Company shall first notify the PS-TS-2 Pool Manager of the alleged violations which merit suspension or termination. Such notice must be in writing and must be sent to the PS-TS-2 Pool Manager as specified in the notice provisions of the PS-TS-2 Pool Management Agreement at least five (5) business days prior to the effective date of the suspension or termination.

SPECIAL TERMS AND CONDITIONS

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

T

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

T

SPECIAL TERMS AND CONDITIONS (continued) T

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

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

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

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

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

Standard Rate Rider

PS-TS-2
Pooling Service – Rider TS-2

SPECIAL TERMS AND CONDITIONS (continued)

T

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

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

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate Rider **PS-FT**

Pooling Service – Rate FT

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to “FT Pool Managers”.

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

RATE

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

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

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

CHARACTER OF SERVICE

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

The FT Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of Customers in the FT Pool. The FT Pool Manager shall be subject to the same nomination deadlines as set forth in Rate FT. The Daily Utilization Charge, OFO Penalty and cash-out provision of Rate FT shall be applied against the aggregate volume of all Customers in a specific FT Pool. The FT Pool Manager will be responsible for the payment of the PS-FT Pool Administrative Charge and any Daily Utilization Charges, OFO penalties or monthly cash-out payments incurred by a specific FT Pool as a result of imbalances under Rate FT.

CHARACTER OF SERVICE (continued)

Company shall issue an Operational Flow Order as set forth in Rate FT to the FT Pool Manager during periods when service cannot be provided to meet daily imbalances. T

VARIATIONS IN MMBTU CONTENT

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

SPECIAL TERMS AND CONDITIONS

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

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

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

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

Standard Rate Rider **PS-FT**

Pooling Service – Rate FT

SPECIAL TERMS AND CONDITIONS (continued)

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

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

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

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

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

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State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Standard Rate Rider **EF**

Excess Facilities

APPLICABILITY

In all territory served.

AVAILABILITY OF SERVICE

This rider is available for nonstandard service facilities which are considered to be in excess of the standard facilities that would normally be provided by Company. This rider does not apply to main extensions or to other facilities which are necessary to provide basic gas service. Company reserves the right to decline to provide service hereunder for any project (a) that exceeds $100,000 or (b) where Company does not have sufficient expertise to install, operate, or maintain the facilities or (c) where the facilities do not meet Company's safety requirements, or (d) where the facilities are likely to become obsolete prior to the end of the initial contract term. Customers currently being served under the Excess Facilities Rider pursuant to Original Sheet No. 52 of LG&E's Tariff PSC. of Ky. Gas No. 6, shall continue to be served thereunder.

DEFINITION OF EXCESS FACILITIES

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

EXCESS FACILITIES CHARGE

Company shall provide normal operation and maintenance of the excess facilities. Should the facilities suffer failure, Company will provide for replacement of such facilities and the monthly charge will be adjusted to reflect the installed cost of the replacement facilities. 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	0.47%

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State Regulation and Rates
Louisville, Kentucky

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Standard Rate Rider

EF
Excess Facilities

PAYMENT

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

TERM OF CONTRACT

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

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State Regulation and Rates
Louisville, Kentucky

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Standard Rate Rider **NGV** N

Natural Gas Vehicle Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to municipal, utility, corporate and other fleet operators and public fueling stations meeting the qualifications of, and served under, either Rate IGS or Rate FT for the sole purpose of providing compressed natural gas for use as a fuel in vehicular internal combustion engines. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this Rider.

Service provided under this Rider shall be separately metered. Service for any use of natural gas other than the compression of natural gas for vehicle fuel, such as space heating, water heating, or any direct processing or boiler fuel use, is not permitted under this Rider or through the meter through which service under this Rider is provided.

CHARACTER OF SERVICE

Company will provide Customer with uncompressed natural gas pursuant to either Rate IGS or Rate FT, as applicable. A customer served under Rate IGS that meets the qualifications for service under Rider TS-2 may also transport gas pursuant to Rider TS-2.

Customer shall be responsible for installing, owning, and maintaining all facilities required to operate its fueling station.

The compression of natural gas to the pressure required for use as a motor vehicle fuel will be conducted by Customer using facilities installed, owned and operated by Customer.

RATE

The rates, provisions, and special terms and conditions of Rate IGS, Rider TS-2, or Rate FT as applicable to the Customer shall apply.

Natural Gas Vehicle Service

SPECIAL CONDITIONS

1. Company reserves the right to inspect customer’s premises to ensure gas provided pursuant to this Rider is only used for vehicular fuel. Any other use of gas by Customer may result in termination of service.

2. Service under this Rider shall be performed under a written contract between Customer and Company containing such provisions regarding delivery pressure, indemnification, and other matters as the Company deems necessary or desirable with respect to a particular customer.

3. Customer shall be responsible for and shall reimburse the Company for all taxes (including, but not limited to, any motor vehicle taxes) payable by the Company to any governmental body on sales of gas and/or for services rendered under this Rider.

4. The “Resale of Gas” provision set forth in the “Terms and Conditions” of Company’s Tariff shall not apply to service provided under this Rider. Customer may resell gas received from Company under this Rider for use as a fuel in vehicular internal combustion engines.

5. Customer is solely responsible for compliance with codes and standards, permitting requirements, regulations, and laws related to the use of compressed natural gas and the operation of a natural gas vehicle fueling station, whether as a fleet operation or as a public fueling station. Company is not responsible for vehicle fueling.

TERMS AND CONDITIONS

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

Adjustment Clause

GLT
Gas Line Tracker

APPLICABLE

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

CALCULATION OF THE GAS LINE TRACKER REVENUE REQUIREMENT

The GLT Revenue Requirement includes the following:

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

GLT PROGRAM FACTORS

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

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

GLT RATES

The charges for the respective gas service schedules are:

RGS – Residential Gas Service	$ 1.08
VFD – Volunteer Fire Department Service	$ 1.08
CGS – Commercial Gas Service	$ 4.83
IGS – Industrial Gas Service	$ 42.69
AAGS – As-Available Gas Service	$ 235.45
DGGS – Distributed Generation Gas Service	$ 0.00

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State Regulation and Rates
Louisville, Kentucky

Adjustment Clause

GSC
Gas Supply Clause

APPLICABLE TO

All gas sold.

GAS SUPPLY COST COMPONENT (GSCC)

Gas Supply Cost	$0.50459
Gas Cost Actual Adjustment (GCAA)	0.05750
Gas Cost Balance Adjustment (GCBA)	(0.00584)
Refund Factors (RF) continuing for twelve months from the effective date of each or until Company has discharged its refund obligation thereunder:	
None	
Performance-Based Rate Recovery Component (PBRRC)	0.00503
Total Gas Supply Cost Component Per 100 Cubic Feet (GSCC)	$0.56128

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State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2014-00348 dated October 27, 2014

Adjustment Clause

GSC
Gas Supply Clause

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

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

where:

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

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

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

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

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

(GCAA) is the Gas Cost Actual Adjustment per 100 cubic feet which compensates for differences between the previous three-month period’s expected gas cost and the actual cost of gas during that three-month period, plus net uncollectible gas cost portion of bad debt.

(GCBA) is the Gas Cost Balance Adjustment per 100 cubic feet which compensates for any under- or over-collections which have occurred as a result of prior adjustments.

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

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

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

1. A copy of the tariff rate(s) of Company's pipeline transporter(s) applicable to such three-month period.
2. A statement, through the most recent three-month period for which figures are available, setting out the accumulated costs recovered hereunder compared to actual gas supply costs recorded on the books.
3. A statement setting forth the supporting calculations of the Gas Supply Cost and the Gas Cost Actual Adjustment (GCAA) and the Gas Cost Balance Adjustment (GCBA) applicable to such three-month period.

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

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

1. The "Refundable Amount" shall be the amount received by Company as a refund less any portion thereof applicable to gas purchased for electric energy production plus interest at a rate equal to the average of the "3-month commercial paper rate" for the immediately preceding 12-month period, less ½ of 1 percent to cover the cost of refunding in accordance with the Order of the Commission in Case No. 7799-D. Such Refundable Amount shall be divided by the number of hundred cubic feet of gas that Company estimates it will sell to its customers during the twelve-month period which commences with implementation of the next Gas Supply Clause filing, thus determining a "Refund Factor."
2. Effective with the implementation of the next Gas Supply Clause filing, Company will reduce, by the Refund Factor so determined, the Gas Supply Cost Component that would otherwise be applicable during the subsequent twelve-month period. Provided, however, that the period of reduced Gas Supply Cost Component will be adjusted, if necessary, in order to refund, as nearly as possible, the Refundable Amount.
3. In the event of any large or unusual refunds, Company may apply to the Public Service Commission of Kentucky for the right to depart from the refund procedure herein set forth.

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to Residential Gas Service Rate RGS, Volunteer Fire Department
Service Rate VFD, Firm Commercial Gas Service Rate CGS, Firm Industrial Gas Service Rate T
IGS, As-Available Gas Service Rate AAGS, and Firm Transportation Rate FT. T

RATE

The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per 100 cubic feet (Ccf) of monthly gas consumption in accordance with the following formula:

DSMRC = DCR + DRLS + DSMI + DBA + DCCR

Where:

DCR = DSM COST RECOVERY

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

The cost of approved programs shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DCR for such rate class.

DRLS = DSM REVENUE FROM LOST SALES

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

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DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

DRLS = DSM REVENUE FROM LOST SALES (continued)

1. For each upcoming twelve-month period, the estimated reduction in customer usage (in Ccf) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per Ccf for purposes of determining the lost revenue to be recovered hereunder for each customer class. The non-variable revenue requirement is defined as the weighted average price per Ccf of expected Distribution Cost Component billings for the customer classes.

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

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

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

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

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DATE EFFECTIVE: With Bills Rendered On and
After December 31, 2011

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2011-00134 dated November 9, 2011

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

DSMI = DSM INCENTIVE (continued)

The DSM incentive amount shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DSMI. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

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

(1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.

(2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.

(3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.

(4) For the DBA, the balance adjustment amount will be determined by calculating the difference between the amount billed during the twelve-month period from application of the DBA unit charges and the balance adjustment amount established for the same twelve-month period.

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

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Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

DCCR = DSM CAPITAL COST RECOVERY

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

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

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

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

CHANGES TO DSMRC

The filing of modifications to the DSMRC that require changes in the DCR component shall be made at least two (2) months prior to the beginning of the effective period for billing. Modifications to other components of the DSMRC shall be made at least thirty (30) days prior to the effective period for billing. Each filing shall include the following information as applicable:

(1) A detailed description of each DSM program developed by the collaborative process, the total cost of each program over the twelve-month period, an analysis of expected resource savings, information concerning the specific DSM or efficiency measures to be installed, and any applicable studies that have been performed, as available.

(2) A statement setting forth the detailed calculation of the DCR, DRLS, DSMI, DBA and DSMRC.

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

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DATE EFFECTIVE: May 31, 2012

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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 RGS and VFD Standard Gas Rate Schedules.

Residential Conservation / Home Energy Performance Program

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

Residential Low Income Weatherization Program (WeCare)

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

Smart Energy Profile

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

Residential New Construction Program

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

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State Regulation and Rates
Louisville, Kentucky

PROGRAMMATIC CUSTOMER CHARGES (continued)

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

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

Commercial Customer Program Participation Incentives:
The following Demand Side Management programs are available to commercial customers receiving service from the Company on the CGS, IGS, AAGS, and FT Standard Gas Rate T
Schedules. T

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

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

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors:

Residential Gas Service Rate RGS and Volunteer Fire Department Service Rate VFD	Energy Charge	T T
DSM Cost Recovery Component (DCR)	$ 0.01645 per Ccf	
DSM Revenues from Lost Sales (DRLS)	$ 0.00316 per Ccf	
DSM Incentive (DSMI)	$ 0.00075 per Ccf	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per Ccf	
DSM Balance Adjustment (DBA)	$ (0.00413) per Ccf	
Total DSMRC for Rates RGS and VFD	$ 0.01623 per Ccf	

Firm Commercial Gas Service Rate CGS, As-Available Gas Service Rate AAGS,* and Firm Transportation Service Rate FT*	Energy Charge	T T T
DSM Cost Recovery Component (DCR)	$ 0.00089 per Ccf	
DSM Revenues from Lost Sales (DRLS)	$ 0.00000 per Ccf	
DSM Incentive (DSMI)	$ 0.00000 per Ccf	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per Ccf	
DSM Balance Adjustment (DBA)	$ 0.00004 per Ccf	
Total DSMRC for Rates CGS, AAGS, and FT	$ 0.00093 per Ccf	T

* This charge does not apply to industrial customers taking service under these rates because the Company currently does not offer industrial DSM programs. T T

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Adjustment Clause **PBR**

Experimental Performance Based Rate Mechanism

APPLICABLE

To all gas sold.

RATE MECHANISM

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

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

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

Where:

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

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

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

Where:

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

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

GAIF

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

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State Regulation and Rates
Louisville, Kentucky

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Adjustment Clause **PBR**

Experimental Performance Based Rate Mechanism

The BGC shall include two benchmark components as follows:

BGC = TABMGCC + HRF

Where:

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

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

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

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

Where:

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

i represents each supply area.

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

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

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

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State Regulation and Rates
Louisville, Kentucky

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2009-00550 dated April 30, 2010

Adjustment Clause **PBR**

Experimental Performance Based Rate Mechanism

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

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

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

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

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

Where:

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

The indices for each supply zone are as follows:

SAI (TGT-SL)

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

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

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas Zone SL.

SAI (TGT-1)

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

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

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas Zone1.

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SAI (TGT-4)

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

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

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Northeast – Lebanon Hub.

SAI (TGPL-0)

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

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

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee Zone 0.

SAI (TGPL-1)

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

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

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee 500 leg.

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

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

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

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Prices of Spot Gas Delivered to Pipeline for Dominion Transmission Inc. - Appalachia.

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

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

Shared Expenses = AGC - BGC

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

Shared Savings = BGC – AGC

TIF

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

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

TABMGTC = Annual Sum of Monthly BMGTC

Where:

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

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State Regulation and Rates
Louisville, Kentucky

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Adjustment Clause **PBR**

Experimental Performance Based Rate Mechanism

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

Where:

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

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

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

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

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

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

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

Where:

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

TPCR is the applicable Tariffed Pipeline Commodity Rate.

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

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

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

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

Shared Expenses = TAAGTC – TABMGTC

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

Shared Savings = TABMGTC - TAAGTC

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

OSSIF

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

Net Revenue is calculated as follows:

NR = OSREV - OOPC

Where:

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

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

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

Where:

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: November 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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2009-00550 dated April 30, 2010

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

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

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

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

ACSP

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

Where:

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

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

Where:

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

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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

BA

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

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

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

Review

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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2009-00550 dated April 30, 2010

Adjustment Clause **WNA**

Weather Normalization Adjustment Clause Applicable to Rates RGS and CGS

WEATHER NORMALIZATION ADJUSTMENT (WNA)

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

Determination of WNA

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

Weather Normalization Adjustment will be calculated using the following formula:

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

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00459 dated July 30, 2010

Adjustment Clause

Franchise Fee

APPLICABILITY

All gas rate schedules.

MONTHLY CHARGE

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

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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2009-00549 dated July 30, 2010**

Adjustment Clause

ST
School Tax

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

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

RATE

The utility gross receipts license tax authorized under state law.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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2009-00549 dated July 30, 2010

Adjustment Clause

HEA
Home Energy Assistance

APPLICABLE
In all territory served.

AVAILABILITY
To all residential customers.

RATE
$0.25 per meter per month.

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

SERVICE PERIOD
The Home Energy Assistance charge will be applied to all residential gas bills rendered during the billing cycles commencing January 1, 2013 until the effective date of new base rates, or as otherwise directed by the Public Service Commission. The HEA program is approved through September 30, 2015. 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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

Customer Bill of Rights

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

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

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

COMPANY TERMS AND CONDITIONS.

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

COMPANY AS A FEDERAL CONTRACTOR

T

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

ASSIGNMENT

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

T

TERMS AND CONDITIONS

General

RENEWAL OF CONTRACT

T

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

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

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

SUPERSEDE PREVIOUS TERMS AND CONDITIONS

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

TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

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

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

Where an unusual expenditure for construction or equipment is necessary or where the proposed manner of using gas service is clearly outside the scope of Company's standard rate schedules, Company may establish special terms and require special contracts giving effect to such unusual circumstances.

TRANSFER OF APPLICATION

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

OPTIONAL RATES

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

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

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

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

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

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DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

TERMS AND CONDITIONS

Customer Responsibilities

CUSTOMER'S EQUIPMENT AND INSTALLATION.

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

All piping, appliances, and other gas equipment and apparatus, except the meter, regulator, and any gas riser or service line the Company has installed, repaired, or replaced, located on and within the Customer's premises beyond point of connection with Company's Service Connection at the property line shall be furnished and installed by and at the expense of Customer, and shall be maintained by Customer in good and safe condition. Company assumes no responsibility whatsoever for the condition of Customer's piping, apparatus or appliances, nor for the maintenance or renewal of any portion thereof.

OWNER'S CONSENT TO OCCUPY

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

ACCESS TO PREMISES AND EQUIPMENT

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

PROTECTION OF COMPANY'S PROPERTY

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

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

TERMS AND CONDITIONS

Customer Responsibilities

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED (continued)

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

LIABILITY

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

NOTICE TO COMPANY OF CHANGES IN CUSTOMER'S LOAD

The service pipes, meters, and appurtenances supplied by Company for the rendition of gas service to its customers have a definite capacity. In the event that Customer contemplates any material increase in Customer’s connected load, whether in a single increment or over an extended period, Customer shall immediately give Company written notice of this fact so as to enable it to enlarge the capacity of such equipment. In case of failure to give such notice, Customer may be held liable for any damage done to meters, regulators, or other equipment of Company caused by such material increase in Customer's connected load.

PERMITS

Customer shall obtain or cause to be obtained all permits, easements, or certificates, except street permits, necessary to give Company or its agents access to Customer's premises and equipment and to enable its service to be connected therewith. In case Customer is not the owner of the premises or of intervening property between the premises and Company's distribution mains, Customer shall obtain from the proper owner or owners the necessary consent to the installation and maintenance in said premises and across such intervening property of Customer's piping and facilities required for the supply of gas service to Customer. Provided, however, to the extent permits, easements, or certificates are necessary for the installation and maintenance of Company-owned facilities, Company shall obtain the aforementioned consent.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
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TERMS AND CONDITIONS

Customer Responsibilities

PERMITS (continued)

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.

COMPANY-OWNED SERVICE LINES

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

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

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

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

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

TERMS AND CONDITIONS

Company Responsibilities

METERING

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

POINT OF DELIVERY OF GAS

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

If the Service Line is owned by the Customer, the point of delivery of gas supplied by the Company shall be at the point where the gas passes from the pipes of Company’s Service Connection into Customer’s Service Line, irrespective of the location of the metering and regulation equipment.

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

COMPANY'S EQUIPMENT AND INSTALLATION

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

The Company will furnish, install, and maintain at its expense the necessary meter, regulator, and connections which will be located at or near the building, at the discretion or judgment of the Company. Suitable site or location for the meter, meter stand (including meter riser), and regulator and connections shall be provided by the Customer and title to this equipment shall remain in the Company with the right to install, operate, maintain, and remove same and no charge shall be made by the Customer for use of the premises as occupied or used. Customer shall protect such property of Company from loss or damage, and no one who is not an agent of Company shall be permitted to remove, damage or tamper with the same. Customer shall execute a reasonable form of easement agreement, if requested by Company.

TERMS AND CONDITIONS

Company Responsibilities

COMPANY'S EQUIPMENT AND INSTALLATION (continued)

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 gas requirements.

COMPANY NOT LIABLE FOR INTERRUPTIONS

Company will exercise reasonable care and diligence in an endeavor to supply gas service continuously and without interruption, except as provided in the terms of certain rate schedules; however, Company does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay or failure of gas service not caused by the willful negligence of Company, or resulting from any cause or circumstance beyond the reasonable control of Company.

COMPANY NOT LIABLE FOR DAMAGE ON CUSTOMER’S PREMISES

Company is merely a supplier of gas service delivered at Company’s property line, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or property of the Customer or of third persons resulting from the presence, use or abuse of gas on the Customer’s premises or resulting from defects in or accidents to any of Customer’s piping, equipment, apparatus or appliances, or resulting from any cause whatsoever other than the negligence of Company.

LIABILITY

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

OBLIGATION TO SERVE

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any

TERMS AND CONDITIONS

Company Responsibilities

Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. Company and Customer may mutually agree to enter into a special contract for standby, back-up, supplemental or other service subject to the approval of the Kentucky Public Service Commission.

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

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

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

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

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

PURCHASE OF CERTAIN CUSTOMER-OWNED GAS SERVICE ENTRANCES AND RISERS.

LG&E will reimburse its gas customers who have replaced their service entrances or gas risers (or both) between January 1, 2011 and December 31, 2012. Customers must notify LG&E if they desire such reimbursement. LG&E has no obligation to seek out such customers. LG&E will post on its website a notice of the availability of this reimbursement. The reimbursement will be in the amount of the customers' reasonable costs of replacing such service entrances or gas risers (or both), which must be demonstrated to LG&E's reasonable satisfaction. Customers disputing the amount of reimbursement may contact the Commission. LG&E will reimburse only owners of affected properties, each of whom must have owned the affected property at the time of the replacement of the service entrance or gas riser.

TERMS AND CONDITIONS

Character of Service

HEATING VALUE

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

STANDARD PRESSURE AND MEASUREMENT BASE

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

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

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

DELIVERY PRESSURE T

Company shall not be obligated to provide gas service to any Customer at a minimum delivery T
pressure greater than 50 psig or the expected minimum pipeline pressure, whichever is less. T

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Billing

METER READINGS AND BILLS

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

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

Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within sixteen (16) business days (no less than twenty-two (22) calendar days) from the 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

TERMS AND CONDITIONS

Billing

METER READINGS AND BILLS (continued)

receipt of such pledge or notice. There will be no adverse credit impact on the customer's payment and credit record, including credit scoring, both internally and externally, and the account will not be considered delinquent for any purpose if the Company receives the customer's payment within fifteen days after the date on which the Company issues the customer's bill.

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

READING OF SEPARATE METERS NOT COMBINED

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

CUSTOMER RATE MIGRATION

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

MONITORING OF CUSTOMER USAGE

In order to detect unusual deviations in individual Customer consumption, Company will monitor the usage of each Customer at least once 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 the Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of the Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, Company may contact Customer by telephone or in writing to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume, or known leaks in the Customer's service line. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether the results show the meter is within the limits allowed by 807 KAR 5:022, Section 8(3)(a)1, and Section 8(3)(b)1. Company will notify the customers of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 11(4) and (5).

TERMS AND CONDITIONS

Billing

RESALE OF GAS

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

TERMS AND CONDITIONS

Deposits

GENERAL

1) Company may require a cash deposit or other guaranty from customers to secure payment of bills in accordance with 807 KAR 5:006, Section 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 customers the option of paying all or a portion of their deposits in installments over a period not to exceed the first four (4) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.
5) The General Terms and Conditions regarding Deposits set forth above shall not apply to, and shall be superseded by, the deposit requirements set forth in Section 3 of the Special Terms and Conditions contained in Standard Rate Rider PS-TS-2 (Sheet No. 59.5), Standard Rate Rider PS-TS (Sheet No. 60.1), and Standard Rate Rider PS-FT (Sheet No. 61.1).

RESIDENTIAL

1) Residential customers are those customers served under Residential Gas Service, Sheet No. 5.
2) The deposit for a residential customer is in the amount of $100.00, which is calculated in I
   accordance with 807 KAR5:006, Section 8(1)(d). For combination gas and electric
   customers, the total deposit will be $260.00. I
3) Company shall retain Customer’s deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Deposits

RESIDENTIAL (continued)

4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated, at Customer’s request, and based on Customer’s actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 8(1)(d).
2) For customers not meeting the parameters of GENERAL ¶ 2, Company may retain Customer’s deposit as long as Customer remains on service.
3) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer’s request, and based on Customer’s actual usage. If the deposit on account differs from the recalculated amount by more than ten percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to residential customers and to small commercial customers served under Rates CGS. Small business customers with combined gas and electric services must be served exclusively under General Service Rate GS for their electric service. Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in the plan at any time.

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

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

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

TERMS AND CONDITIONS

Bill Format

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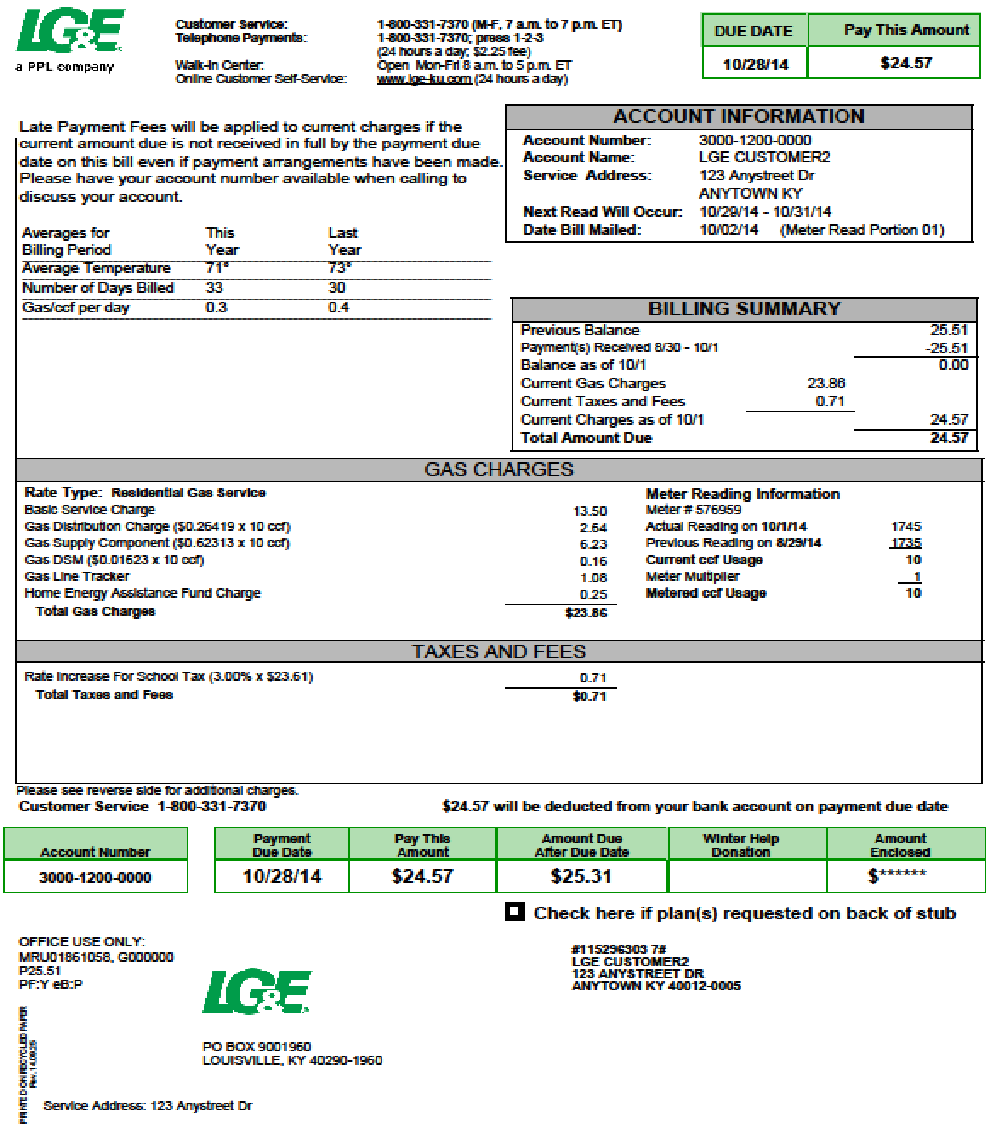

LG&E
a PPL company

Customer Service: 1-800-331-7370 (M-F, 7 a.m. to 7 p.m. ET)
Telephone Payments: 1-800-331-7370; press 1-2-3
(24 hours a day; $2.25 fee)
Walk-In Center: Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service: www.lge-ku.com (24 hours a day)

DUE DATE	Pay This Amount
10/28/14	$24.57

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

Averages for Billing Period	This Year	Last Year
Average Temperature	71°	73°
Number of Days Billed	33	30
Gas/ccf per day	0.3	0.4

ACCOUNT INFORMATION

Account Number: 3000-1200-0000
Account Name: LGE CUSTOMER2
Service Address: 123 Anystreet Dr
ANYTOWN KY
Next Read Will Occur: 10/29/14 - 10/31/14
Date Bill Mailed: 10/02/14 (Meter Read Portion 01)

BILLING SUMMARY

Previous Balance		25.51
Payment(s) Received 8/30 - 10/1		-25.51
Balance as of 10/1		0.00
Current Gas Charges	23.86	
Current Taxes and Fees	0.71	
Current Charges as of 10/1		24.57
Total Amount Due		**24.57**

GAS CHARGES

Rate Type: Residential Gas Service

Basic Service Charge	13.50
Gas Distribution Charge ($0.26419 x 10 ccf)	2.64
Gas Supply Component ($0.62313 x 10 ccf)	6.23
Gas DSM ($0.01623 x 10 ccf)	0.16
Gas Line Tracker	1.08
Home Energy Assistance Fund Charge	0.25
Total Gas Charges	**$23.86**

Meter Reading Information

Meter # 576959

Actual Reading on 10/1/14	1745
Previous Reading on 8/29/14	1735
Current ccf Usage	10
Meter Multiplier	1
Metered ccf Usage	10

TAXES AND FEES

Rate Increase For School Tax (3.00% x $23.61)	0.71
Total Taxes and Fees	**$0.71**

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

$24.57 will be deducted from your bank account on payment due date

Account Number	Payment Due Date	Pay This Amount	Amount Due After Due Date	Winter Help Donation	Amount Enclosed
3000-1200-0000	10/28/14	$24.57	$25.31		$******

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

OFFICE USE ONLY:
MRU01861058, G000000
P25.51
PF:Y eB:P

LG&E

PO BOX 9001960
LOUISVILLE, KY 40290-1960

#115296303 7#
LGE CUSTOMER2
123 ANYSTREET DR
ANYTOWN KY 40012-0005

PRINTED ON RECYCLED PAPER

Service Address: 123 Anystreet Dr

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format

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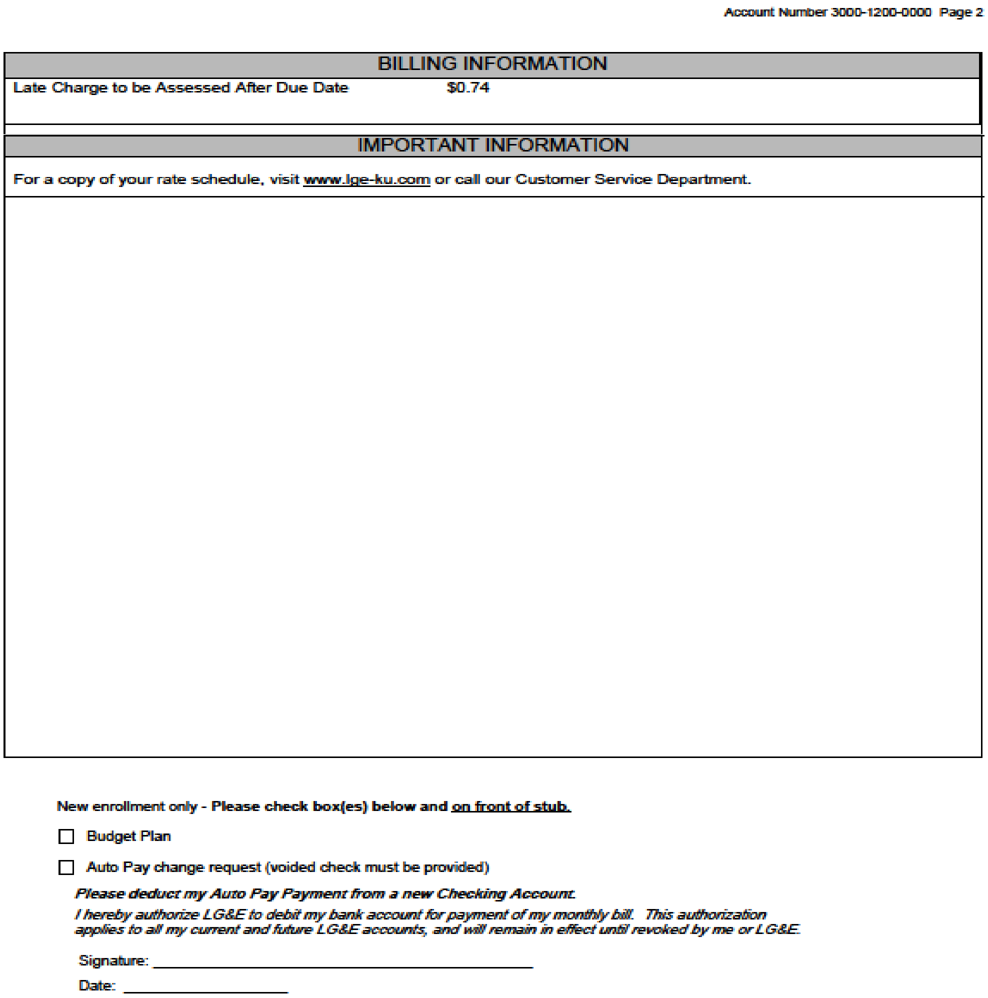

Account Number 3000-1200-0000 Page 2

BILLING INFORMATION	
Late Charge to be Assessed After Due Date	$0.74

IMPORTANT INFORMATION

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

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

☐ Budget Plan

☐ Auto Pay change request (voided check must be provided)

Please deduct my Auto Pay Payment from a new Checking Account.

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

Signature: ____________________________________

Date: _______________

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format

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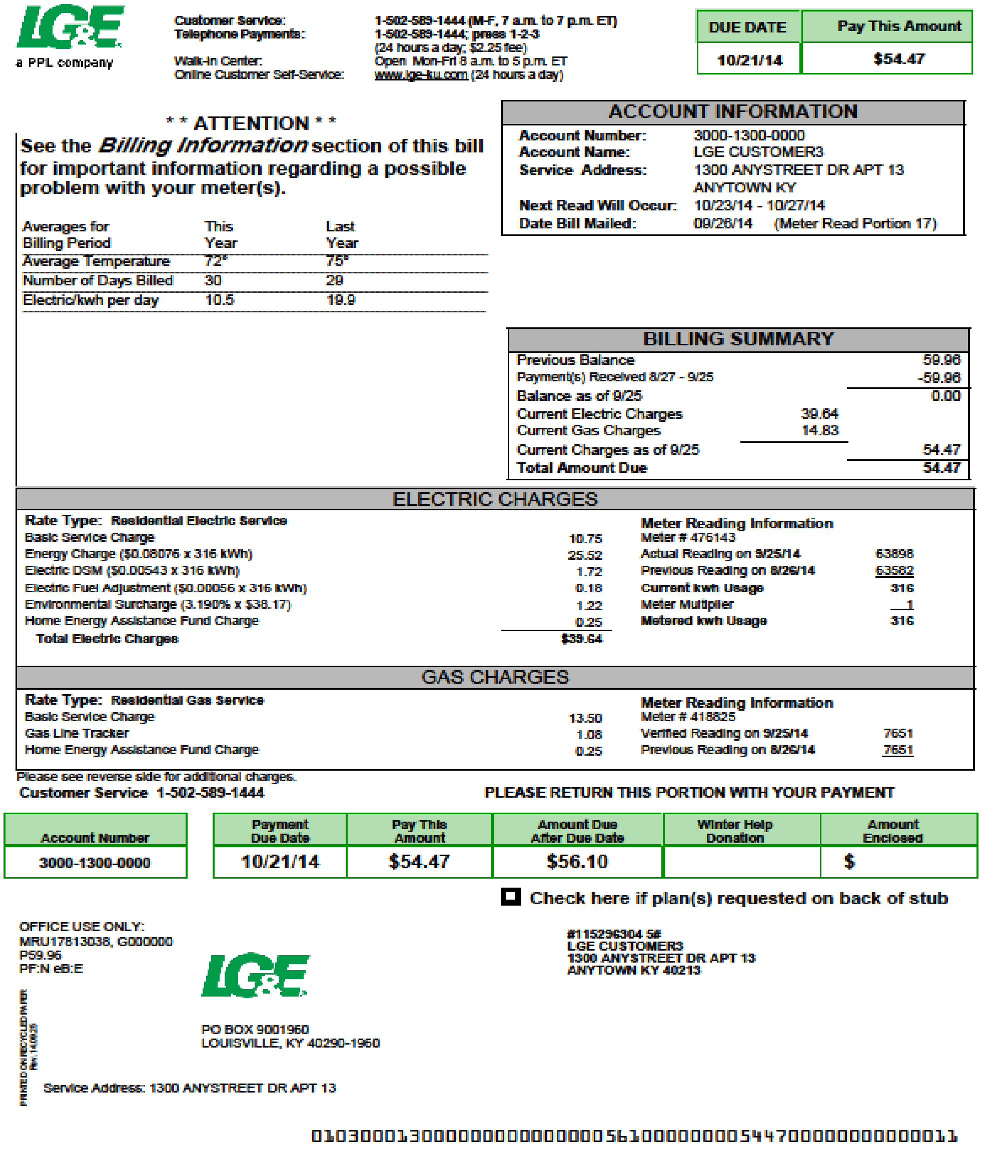

LG&E
a PPL company

Customer Service:	**1-502-589-1444 (M-F, 7 a.m. to 7 p.m. ET)**
Telephone Payments:	**1-502-589-1444; press 1-2-3** (24 hours a day; $2.25 fee)
Walk-In Center:	Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service:	www.lge-ku.com (24 hours a day)

DUE DATE	Pay This Amount
10/21/14	**$54.47**

* * ATTENTION * *

See the *Billing Information* section of this bill for important information regarding a possible problem with your meter(s).

Averages for Billing Period	This Year	Last Year
Average Temperature	72°	75°
Number of Days Billed	30	29
Electric/kwh per day	10.5	19.9

ACCOUNT INFORMATION

Account Number: 3000-1300-0000
Account Name: LGE CUSTOMER3
Service Address: 1300 ANYSTREET DR APT 13
ANYTOWN KY
Next Read Will Occur: 10/23/14 - 10/27/14
Date Bill Mailed: 09/26/14 (Meter Read Portion 17)

BILLING SUMMARY

Previous Balance		59.96
Payment(s) Received 8/27 - 9/25		-59.96
Balance as of 9/25		0.00
Current Electric Charges	39.64	
Current Gas Charges	14.83	
Current Charges as of 9/25		54.47
Total Amount Due		**54.47**

ELECTRIC CHARGES

Rate Type: Residential Electric Service

Basic Service Charge	10.75
Energy Charge ($0.08076 x 316 kWh)	25.52
Electric DSM ($0.00543 x 316 kWh)	1.72
Electric Fuel Adjustment ($0.00056 x 316 kWh)	0.18
Environmental Surcharge (3.190% x $38.17)	1.22
Home Energy Assistance Fund Charge	0.25
Total Electric Charges	**$39.64**

Meter Reading Information
Meter # 476143

Actual Reading on 9/25/14	63898
Previous Reading on 8/26/14	63582
Current kwh Usage	**316**
Meter Multiplier	1
Metered kwh Usage	**316**

GAS CHARGES

Rate Type: Residential Gas Service

Basic Service Charge	13.50
Gas Line Tracker	1.08
Home Energy Assistance Fund Charge	0.25

Meter Reading Information
Meter # 418825

Verified Reading on 9/25/14	7651
Previous Reading on 8/26/14	7651

Please see reverse side for additional charges.
Customer Service 1-502-589-1444

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number
3000-1300-0000

Payment Due Date	Pay This Amount	Amount Due After Due Date	Winter Help Donation	Amount Enclosed
10/21/14	**$54.47**	**$56.10**		**$**

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

OFFICE USE ONLY:
MRU17813038, G000000
P59.96
PF:N eB:E

LG&E

PO BOX 9001960
LOUISVILLE, KY 40290-1960

#115296304 5#
LGE CUSTOMER3
1300 ANYSTREET DR APT 13
ANYTOWN KY 40213

Service Address: 1300 ANYSTREET DR APT 13

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format

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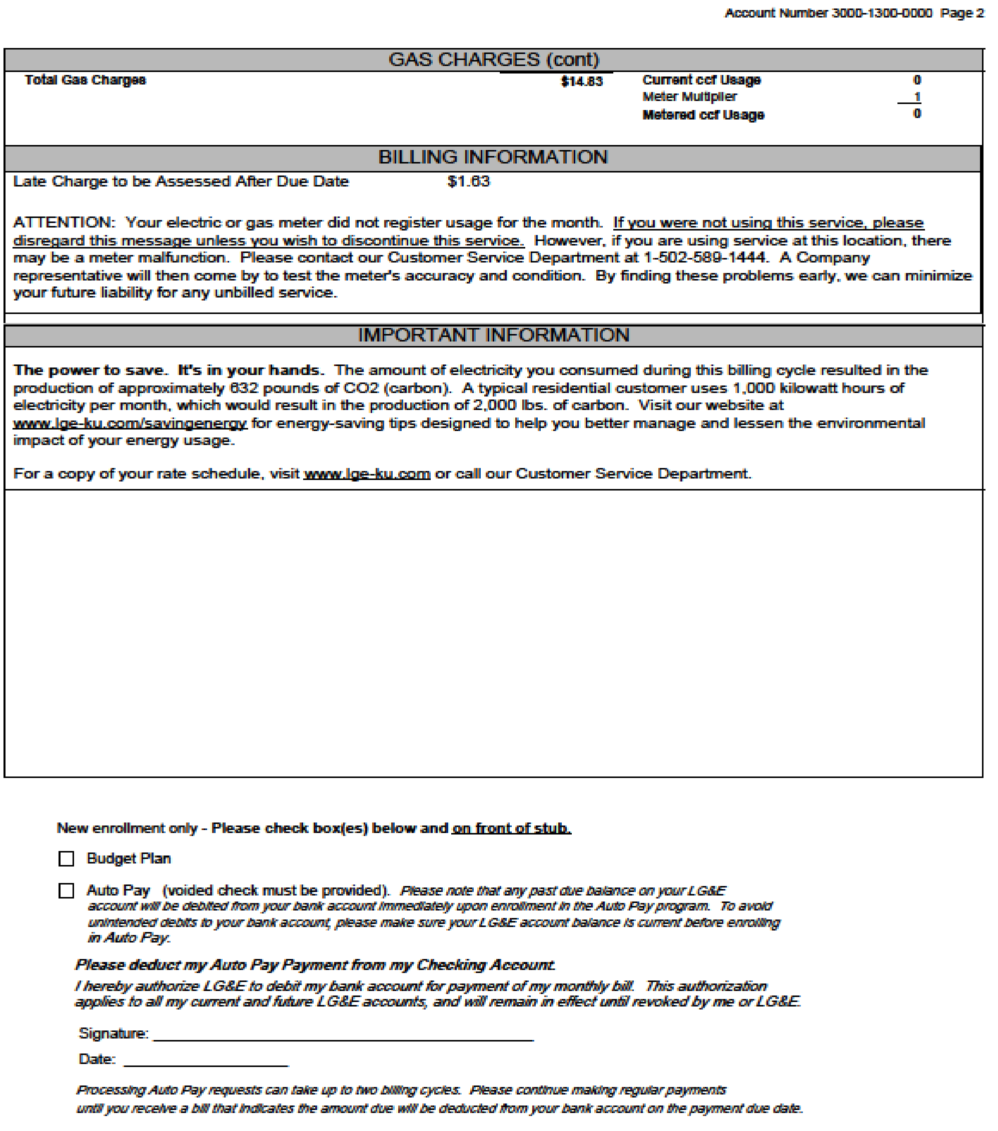

Account Number 3000-1300-0000 Page 2

GAS CHARGES (cont)

Total Gas Charges	**$14.83**	**Current ccf Usage**	**0**
		Meter Multiplier	1
		Metered ccf Usage	**0**

BILLING INFORMATION

Late Charge to be Assessed After Due Date $1.63

ATTENTION: Your electric or gas meter did not register usage for the month. If you were not using this service, please disregard this message unless you wish to discontinue this service. However, if you are using service at this location, there may be a meter malfunction. Please contact our Customer Service Department at 1-502-589-1444. A Company representative will then come by to test the meter's accuracy and condition. By finding these problems early, we can minimize your future liability for any unbilled service.

IMPORTANT INFORMATION

The power to save. It's in your hands. The amount of electricity you consumed during this billing cycle resulted in the production of approximately 632 pounds of CO2 (carbon). A typical residential customer uses 1,000 kilowatt hours of electricity per month, which would result in the production of 2,000 lbs. of carbon. Visit our website at www.lge-ku.com/savingenergy for energy-saving tips designed to help you better manage and lessen the environmental impact of your energy usage.

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

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

☐ Budget Plan

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

Please deduct my Auto Pay Payment from my Checking Account.

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

Signature: ____

Date: ____________________

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Discontinuance of Service

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

A. When Company's or Commission's rules and regulations have not been complied with. However, service may be discontinued or refused only after Company has made a reasonable effort to induce Customer to comply with its rules and then only after Customer has
been given at least 10 days written notice of such intention, mailed or otherwise delivered, T
including, but not limited to, electronic mail, to Customer’s last known address. T

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, T
operation, meter reading, maintenance, or removal of Company's property. Customer shall be
given 15 days written notice (either mailed or otherwise delivered, including, but not limited to, T
electronic mail), of Company's intention to discontinue or refuse service. T

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.

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 lapse in service will not be subject to

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Discontinuance of Service

disconnection unless: (1) such service was provided pursuant to a fraudulent application T
submitted by Customer; (2) Customer and Company have entered into a contractual agreement T
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.

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 T
after the mailing date of original bills unless, prior to discontinuance, a residential customer T
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 T
and federal programs which may be available to aid in payment of bills and the office to
contact for such possible assistance.

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

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Discontinuance of Service

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

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 T
to, electronic mail), based on Customer's payment history provided Company continues to T
provide the required ten (10) days written notice prior to discontinuance of service.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Gas Main Extension Rules

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

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

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

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

TERMS AND CONDITIONS

Gas Main Extension Rules

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

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

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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

TERMS AND CONDITIONS

Gas Service Restrictions

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

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

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

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

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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

TERMS AND CONDITIONS

Gas Service Restrictions

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

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

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

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

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

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

TERMS AND CONDITIONS

Curtailment Rules

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

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

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

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

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

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

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

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

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

TERMS AND CONDITIONS

Curtailment Rules

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

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

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

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

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

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

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

TERMS AND CONDITIONS

Curtailment Rules

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

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

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

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

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

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

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

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

TERMS AND CONDITIONS

Curtailment Rules

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

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

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

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

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

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

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

   Any customer subject to Pro-Rata curtailment in accordance with Section 3 above, who at the end of a month has taken gas in excess of its Authorized Monthly Volumes (excluding Pilot Light Requirements where applicable) for such month, may, in the sole discretion of Company, be subject to a penalty charge applicable to such excess takes of gas at the rate of $15.00 per Mcf plus the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment. Such penalty shall be in addition to the established rate for service. T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Curtailment Rules

Any customer subject to Emergency Curtailment in accordance with Section 4 above, who uses quantities of gas in excess of authorized quantities (excluding Pilot Light Requirements where applicable) during a period of such Emergency Curtailment, may, in the sole discretion of Company, be subject to a penalty charge applicable to such unauthorized takes of gas at the rate of $15.00 per Mcf plus the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment. Such penalty shall be in addition to the established rate for service. T

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

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Special Contracts
Gas

Summary of Proposed Charges Under Gas Special Contracts

Customer 1	Customer Charge:	$300.00 per month
	Administrative Charge	$550.00 per month
	Distribution Charge	$0.1110 per Mcf
	Demand Charge	$2.91 per Mcf
	Daily Storage Charge	$0.1833 per Mcf
Customer 2	Sales Rate:	
	Customer Charge:	$180.00 per month
	Monthly Demand Charge:	$11.69 per Mcf
	Distribution Charge :	$0.3454 per Mcf Delivered
	Gas Supply Cost Component:	Per Rate IGS
	Transportation Rate:	
	Customer Charge:	$800.00 per month
	Demand Charge	$2.53 per Mcf
	Distribution Charge	$0.0508 per Mcf Delivered
	Daily Storage Charge	$0.1833 per Mcf

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(4)
Sponsoring Witness: Edwin R. Staton

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

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

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

PUBLIC SERVICE COMMISSION

OF KENTUCKY

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

P.S.C. Electric No. 10
Canceling P.S.C. Electric No.9

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

ELECTRIC SERVICE

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

PUBLIC SERVICE COMMISSION

OF KENTUCKY

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Fourth Revision of Original Sheet No. 1
Canceling P.S.C. Electric No. 9, Third Revision of Original Sheet No. 1

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DATE OF ISSUE: May 30, 2014

DATE EFFECTIVE: June 30**,** 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Fifth Revision of Original Sheet No. 1.1
Canceling P.S.C. Electric No. 9, Fourth Revision of Original Sheet No. 1.1

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DATE OF ISSUE: February 28, 2014

DATE EFFECTIVE: April 1, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 1.1

GENERAL INDEX
Standard Electric Rate Schedules – Terms and Conditions

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Second Revision of Original Sheet No. 5
Canceling P.S.C. Electric No. 9, First Revision of Original Sheet No. 5

Standard Rate **RS**
Residential Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for single-phase delivery to single family residential service subject to the terms and conditions on Sheet No. 100 of this Tariff.

RATE

Basic Service Charge:	$10.75 per month
Plus an Energy Charge of:	$ 0.08076 per kWh

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

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

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

DUE DATE OF BILL
Customer's payment will be due within 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: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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. T

RATE

Basic Service Charge:	$18.00 per month	I
Plus an Energy Charge of:	$ 0.07618 per kWh	R

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

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

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

DUE DATE OF BILL
Customer's payment will be due within 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: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

The proposed LG&E Residential Time-of-Day Energy Service Rate RTOD-Energy is not part of the current tariff.

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 6

Standard Rate **RTOD-Energy** N

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:	$18.00 per month
Plus an Energy Charge:	
Off Peak Hours:	$0.05271 per kWh
On Peak Hours:	$0.21483 per kWh

ADJUSTMENT CLAUSES

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

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

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

The proposed LG&E Residential Time-of-Day Energy Service Rate RTOD-Energy is not part of the current tariff.

Standard Rate **RTOD-Energy**
Residential Time-of-Day Energy Service N

DETERMINATION OF PRICING PERIODS

Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends. The hours of the pricing periods for the price levels are as follows:

Summer Months of May through September

	Off-Peak	On-Peak
Weekdays	5 PM - 1 PM	1 PM - 5 PM
Weekends	All Hours	

All Other Months of October continuously through April

	Off Peak	On-Peak
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.

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Second Revision of Original Sheet No. 7
Canceling P.S.C. Electric No. 9, First Revision of Original Sheet No. 7

Standard Rate **VFD**
Volunteer Fire Department Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available for single-phase delivery, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load.

DEFINITION
To be eligible for this rate a volunteer fire department is defined as:

1) having at least 12 members and a chief,
2) having at least one firefighting apparatus, and
3) half the members must be volunteers.

RATE

Basic Service Charge:	$10.75 per month
Plus an Energy Charge of:	$ 0.08076 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within 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: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

LG&E Volunteer Fire Department Service Rate VFD was previously located on Sheet No. 7, but is proposed to be moved to Sheet No. 9.

The proposed LG&E Residential Time-of-Day Demand Service Rate RTOD-Demand is not part of the current tariff.

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 7

Standard Rate **RTOD-Demand**

Residential Time-of-Day Demand Service N

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:	$18.00 per month
Plus an Energy Charge:	$ 0.04008 per kWh
Plus a Demand Charge:	
Off Peak Hours:	$ 2.95 per kW
On Peak Hours:	$10.90 per kW

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

The proposed LG&E Residential Time-of-Day Demand Service Rate RTOD-Demand is not part of the current tariff.

Louisville Gas and Electric Company

Standard Rate **RTOD-Demand** N

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 May through September

	Off-Peak	On-Peak
Weekdays	5 PM - 1 PM	1 PM - 5 PM
Weekends	All Hours	

All Other Months of October continuously through April

	Off Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM - 11 AM
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: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

LG&E Volunteer Fire Department Service Rate VFD was previously located on Sheet No. 7, but is proposed to be moved to Sheet No. 9.

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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:	$18.00 per month	I
Plus an Energy Charge of:	$ 0.07618 per kWh	R

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE
The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL
Customer's payment will be due within 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: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Second Revision of Original Sheet No. 10
Canceling P.S.C. Electric No. 9, First Revision of Original Sheet No. 10

Standard Rate **GS**
General Service Rate

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

To general lighting and small power loads for secondary service.

Service under this schedule will be limited to customers whose 12-month-average monthly maximum loads do not exceed 50 kW. Existing customers with 12-month-average maximum monthly loads exceeding 50 kW who are receiving service under P.S.C. Electric No. 6, Fourth Revision of Original Sheet No. 10 as of February 6, 2009, will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer.

RATE

Basic Service Charge:	$20.00 per month for single-phase service $35.00 per month for three-phase service
Plus an Energy Charge of:	$ 0.09134 per kWh

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

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 the customer during the 15-minute period of maximum use during the month.

MINIMUM CHARGE

The Basic Service Charge shall be the Minimum Charge.

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 10

Standard Rate **GS**
General Service Rate

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

To general lighting and small power loads for secondary service.

Service under this schedule will be limited to customers whose 12-month-average monthly maximum loads do not exceed 50 kW. Existing customers with 12-month-average maximum monthly loads exceeding 50 kW who are receiving service under P.S.C. Electric No. 6, Fourth Revision of Original Sheet No. 10 as of February 6, 2009, will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer.

RATE

Basic Service Charge:	$25.00 per month for single-phase service $40.00 per month for three-phase service	I I
Plus an Energy Charge of:	$ 0.09245 per kWh	I

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD

If Company determines based on Customer's usage history that Customer may be exceeding the maximum load permitted under Rate GS, Company may, at its discretion, equip Customer with a meter capable of measuring demand to determine Customer's continuing eligibility for Rate GS. If Customer is equipped with a demand-measuring meter, Customer's load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

MINIMUM CHARGE

The Basic Service Charge shall be the Minimum Charge.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 10.1

Standard Rate **GS**
General Service Rate

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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 10.1

Standard Rate **GS**
General Service Rate

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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Third Revision of Original Sheet No. 15
Canceling P.S.C. Electric No. 9, Second Revision of Original Sheet No. 15

Standard Rate **PS**
Power Service Rate

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rate schedule is available for secondary or primary service.

Service under this schedule will be limited to customers whose 12-month-average monthly minimum secondary loads exceed 50 kW and whose 12-month-average monthly maximum loads do not exceed 250 kW. Secondary or primary customers receiving service under P.S.C. of Ky. Electric No. 6, Fourth Revision of Original Sheet No. 15, Large Commercial Rate LC, and Fourth Revision of Original Sheet No. 25, Large Power Industrial Rate LP, as of February 6, 2009, with loads not meeting these criteria will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer.

RATE

	Secondary	Primary
Basic Service Charge per month:	$90.00	$170.00
Plus an Energy Charge per kWh of:	$ 0.04060	$ 0.03926
Plus a Demand Charge per kW of:		
Summer Rate: (Five Billing Periods of May through September)	$16.40	$ 13.95
Winter Rate: (All other months)	$14.01	$ 11.66

Where the monthly billing demand is the greater of:

a) the maximum measured load in the current billing period but not less than 50 kW for secondary service or 25 kW for primary service, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 60% of the contract capacity based on the maximum load expected on the system or facilities specified by Customer.

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 15

Standard Rate **PS**
Power Service Rate

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rate schedule is available for secondary or primary service.

Service under this schedule will be limited to customers whose 12-month-average monthly minimum secondary loads exceed 50 kW and whose 12-month-average monthly maximum loads do not exceed 250 kW. Secondary or primary customers receiving service under P.S.C. of Ky. Electric No. 6, Fourth Revision of Original Sheet No. 15, Large Commercial Rate LC, and Fourth Revision of Original Sheet No. 25, Large Power Industrial Rate LP, as of February 6, 2009, with loads not meeting these criteria will continue to be served under this rate at their option. If Customer is taking service under this rate schedule and subsequently elects to take service under another rate schedule, Customer may not again take service under this rate schedule unless and until Customer meets the Availability requirements that would apply to a new customer.

RATE

	Secondary	Primary	
Basic Service Charge per month:	$90.00	$200.00	I
Plus an Energy Charge per kWh of:	$ 0.04071	$ 0.03964	I
Plus a Demand Charge per kW of:			
Summer Rate: (Five Billing Periods of May through September)	$17.33	$ 14.62	I
Winter Rate: (All other months)	$14.94	$ 12.33	I

Where the monthly billing demand is the greater of:

a) the maximum measured load in the current billing period but not less than 50 kW for secondary service or 25 kW for primary service, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 60% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer. T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 15.1
Canceling P.S.C. Electric No. 9, 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
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed on the measured kVA times 90 percent of the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD).

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured X 90\%}}{\text{Power Factor (in Percent)}}$$

DUE DATE OF BILL

Customer's payment will be due within 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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 15.1

Standard Rate **PS**
Power Service Rate

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the month.

Company reserves the right to place a kVA meter and base the billing demand on the measured kVA. The charge will be computed on the measured kVA times 90 percent of the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD).

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured X 90\%}}{\text{Power Factor (in Percent)}}$$

DUE DATE OF BILL

Customer's payment will be due within 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: November 26, 2014

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Third Revision of Original Sheet No. 20
Canceling P.S.C. Electric No. 9, 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 average loads exceed 250 kW and whose 12-month-average monthly maximum average loads do not exceed 5,000 kW.

RATE

Basic Service Charge per month:	$200.00
Plus an Energy Charge per kWh of:	$ 0.03990
Plus a Maximum Load Charge per kW of:	
Peak Demand Period	$ 6.11
Intermediate Demand Period	$ 4.51
Base Demand Period	$ 4.00

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kW, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 of:	$ 0.04048	I
Plus a Maximum Load Charge per kW of:		
Peak Demand Period	$ 6.37	I
Intermediate Demand Period	$ 4.76	I
Base Demand Period	$ 4.26	I

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kW, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 20.1
Canceling P.S.C. Electric No. 9, 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, of the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD)

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured x 90\%}}{\text{Power Factor (in percent)}}$$

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within 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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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, of the applicable kW charge.

In lieu of placing a kVA meter, Company may adjust the measured maximum load for billing purposes when the power factor is less than 90 percent in accordance with the following formula: (BASED ON POWER FACTOR MEASURED AT THE TIME OF MAXIMUM LOAD)

$$\text{Adjusted Maximum kW Load for Billing Purposes} = \frac{\text{Maximum kW Load Measured x 90\%}}{\text{Power Factor (in percent)}}$$

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

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State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2012-00222 dated December 20, 2012

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: January 31, 2013

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
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Louisville, Kentucky

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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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Second Revision of Original Sheet No. 22
Canceling P.S.C. Electric No. 9, First Revision of Original Sheet No. 22

Standard Rate **ITODP**

Industrial Time-of-Day Primary Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is available for industrial primary service. Service under this schedule will be limited to customers whose 12-month-average monthly minimum average loads exceed 250 kVA and whose 12-month-average monthly maximum new loads do not exceed 50,000 kVA. Existing customers may increase loads to a maximum of 75,000 kVA by up to 2,000kVA per year or in greater increments with approval of Company's transmission operator.

RATE

Basic Service Charge per month:	$300.00
Plus an Energy Charge per kWh of:	$ 0.03538
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 4.63
Intermediate Demand Period	$ 3.79
Base Demand Period	$ 3.63

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

The current LG&E Industrial Time-of-Day Primary Service Rate ITODP is proposed to be combined with the current Commercial Time-of Day Primary Service Rate CTODP. The new combined rate will be named Time-of-Day Primary Service Rate TODP.

Standard Rate **ITODP**

Industrial Time-of-Day Primary Service

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within 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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

The current LG&E Industrial Time-of-Day Primary Service Rate ITODP is proposed to be combined with the current Commercial Time-of Day Primary Service Rate CTODP. The new combined rate will be named Time-of-Day Primary Service Rate TODP.

Standard Rate

CTODP
Commercial Time-of-Day Primary Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is available for commercial primary service. Service under this schedule will be limited to customers whose 12-month-average monthly minimum average loads exceed 250 kVA and whose 12-month-average monthly maximum new loads do not exceed 50,000 kVA. Existing customers may increase loads to a maximum of 75,000 kVA by up to 2,000kVA per year or in greater increments with approval of Company's transmission operator.

RATE

Basic Service Charge per month:	$300.00
Plus an Energy Charge per kWh of:	$ 0.03810
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 5.83
Intermediate Demand Period	$ 4.13
Base Demand Period	$ 3.98

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

The current LG&E Commercial Time-of-Day Primary Service Rate CTODP is proposed to be combined with the current Industrial Time-of Day Primary Service Rate ITODP. The new combined rate will be named Time-of-Day Primary Service Rate TODP.

Standard Rate **CTODP**

Commercial Time-of-Day Primary Service

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within 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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

The current LG&E Commercial Time-of-Day Primary Service Rate CTODP is proposed to be combined with the current Industrial Time-of Day Primary Service Rate ITODP. The new combined rate will be named Time-of-Day Primary Service Rate TODP.

LG&E Proposed Time-of-Day Primary Service Rate TODP is a combination of the current Industrial Time-of-Day Primary Service Rate ITODP and the current Commercial Time-of-Day Primary Service Rate CTODP, and is not currently available.

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 22

Standard Rate **TODP** N

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:	$300.00
Plus an Energy Charge per kWh of:	$ 0.03823
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 5.04
Intermediate Demand Period	$ 3.69
Base Demand Period	$ 3.54

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

LG&E Proposed Time-of-Day Primary Service Rate TODP is a combination of the current Industrial Time-of-Day Primary Service Rate ITODP and the current Commercial Time-of-Day Primary Service Rate CTODP, and is not currently available.

N

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 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: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Second Revision of Original Sheet No. 25
Canceling P.S.C. Electric No. 9, First Revision of Original Sheet No. 25

Standard Rate **RTS**
Retail Transmission Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is available for transmission service. Service under this schedule will be limited to customers whose 12-month-average monthly maximum new loads do not exceed 50,000 kVA. Existing customers may increase loads to a 12-month-average monthly maximum of 75,000 kVA by up to 2,000 kVA per year or in greater increments with approval of Company's transmission operator.

RATE

Basic Service Charge per month:	$750.00
Plus an Energy Charge per kWh of:	$ 0.03610
Plus a Maximum Load Charge per kVA of:	
Peak Demand Period	$ 4.55
Intermediate Demand Period	$ 3.00
Base Demand Period	$ 2.75

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 20

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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- T
average monthly minimum demand exceeding 250 kVA; and (2) whose new or additional load T
receives any required approval of Company's transmission operator. T

RATE

Basic Service Charge per month:	$1,000.00	I
Plus an Energy Charge per kWh of:	$ 0.03712	I
Plus a Maximum Load Charge per kVA of:		
Peak Demand Period	$ 4.67	I
Intermediate Demand Period	$ 3.12	I
Base Demand Period	$ 2.87	I

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
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ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 25.1

Standard Rate **RTS**
Retail Transmission Service

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within 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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

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DATE OF ISSUE: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Second Revision of Original Sheet No. 30
Canceling P.S.C. Electric No. 9, First Revision of Original Sheet No. 30

Standard Rate **FLS**
Fluctuating Load Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available for primary or transmission service to customers up to an aggregate of two hundred (200) MVA for all customers taking service under this schedule and under the Fluctuating Load Service FLS schedule of Kentucky Utilities Company. This schedule is restricted to individual customers whose monthly demand is twenty (20) MVA or greater. A customer is defined as a fluctuating load if that customer's load either increases or decreases twenty (20) MVA or more per minute or seventy (70) MVA or more in ten (10) minutes when such increases or decreases exceed one (1) occurrence per hour during any hour of the billing month.

Subject to the above aggregate limit of two hundred (200) MVA, this schedule is mandatory for all customers whose load is defined as fluctuating and not served on another standard rate schedule as of July 1, 2004.

BASE RATE

	Primary	Transmission
Basic Service Charge per month:	$750.00	$750.00
Plus an Energy Charge per kWh of:	$ 0.03610	$ 0.03610
Plus a Maximum Load Charge per kVA of:		
Peak Demand Period	$ 2.94	$ 2.94
Intermediate Demand Period	$ 1.89	$ 1.89
Base Demand Period	$ 1.89	$ 1.14

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 20,000 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: */s/* Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 30

Standard Rate **FLS**
Fluctuating Load Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available for primary or transmission service to customers up to an aggregate of two hundred (200) MVA for all customers taking service under this schedule and under the Fluctuating Load Service FLS schedule of Kentucky Utilities Company. This schedule is restricted to individual customers whose monthly demand is twenty (20) MVA or greater. A customer is defined as a fluctuating load if that customer's load either increases or decreases twenty (20) MVA or more per minute or seventy (70) MVA or more in ten (10) minutes when such increases or decreases exceed one (1) occurrence per hour during any hour of the billing month.

Subject to the above aggregate limit of two hundred (200) MVA, this schedule is mandatory for all customers whose load is defined as fluctuating and not served on another standard rate schedule as of July 1, 2004.

BASE RATE

	Primary	Transmission	
Basic Service Charge per month:	$1,000.00	$1,000.00	I
Plus an Energy Charge per kWh of:	$ 0.03709	$ 0.03709	I
Plus a Maximum Load Charge per kVA of:			
Peak Demand Period	$ 3.02	$ 3.02	I
Intermediate Demand Period	$ 1.94	$ 1.94	I
Base Demand Period	$ 1.94	$ 1.17	I

Where:
the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:
a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and
the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the current billing period but not less than 20,000 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: */s/* Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 30.1

Standard Rate **FLS**

Fluctuating Load Service

ADJUSTMENT CLAUSES

The amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kVA demand delivered to the customer during the 5-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Intermediate	Peak
Weekdays	All Hours	10 A.M. – 10 P.M.	1 P.M. – 7 P.M.
Weekends	All Hours		

All other months of October continuously through April

	Base	Intermediate	Peak
Weekdays	All Hours	6 A.M. – 10 P.M.	6 A.M. – 12 Noon
Weekends	All Hours		

DUE DATE OF BILL

Customer's payment will be due within 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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 30.1

Standard Rate **FLS**

Fluctuating Load Service

ADJUSTMENT CLAUSES

The amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

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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.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 30.2
Canceling P.S.C. Electric No. 9, Original Sheet No. 30.2

Standard Rate **FLS**
Fluctuating Load Service

TERM OF CONTRACT

Unless terminated by mutual agreement, the initial term of contract for service shall be for a fixed term of five (5) years with successive one (1) year term renewal until canceled by either party giving at least one (1) year written notice to the other prior to the end of the initial term or the then current annual renewal period, as applicable.

PROTECTION OF SERVICE

Where Customer’s use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer’s own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other undesirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer’s use of Company’s service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 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,

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 30.2

Standard Rate **FLS**
Fluctuating Load Service

TERM OF CONTRACT

Unless terminated by mutual agreement, the initial term of contract for service shall be for a fixed term of five (5) years with successive one (1) year term renewal until canceled by either party giving at least one (1) year written notice to the other prior to the end of the initial term or the then current annual renewal period, as applicable.

PROTECTION OF SERVICE

Where Customer’s use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer’s own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other undesirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer’s use of Company’s service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 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.

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State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 30.3
Canceling P.S.C. Electric No. 9, Original Sheet No. 30.3

Standard Rate **FLS**
Fluctuating Load Service

if any, under the CURTAILABLE SERVICE RIDERS CSR10 and CSR30. Company's right to interrupt under this provision is restricted to responses to unplanned outage or de-rates of LG&E and KU Energy LLC System ("LKE System") owned or purchased generation or when Automatic Reserve Sharing is invoked. LKE System, as used herein, shall consist of LG&E and KU. At customer's request, Company shall provide documentation of the need for interruption under this provision within sixty (60) days of the end of the applicable billing period.

LIABILITY

In no event shall Company have any liability to the Customer or any other party affected by the electrical service to the Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to the Customer or any other party. In the event that the Customer's use of Company's service causes damage to Company's property or injuries to persons, the Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 30.3

Standard Rate **FLS**
Fluctuating Load Service

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Second Revision of Original Sheet No. 35
Canceling P.S.C. Electric No. 9, 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
High Pressure Sodium				
452	Cobra Head	16,000	0.181	$12.82
453	Cobra Head	28,500	0.294	15.08
454	Cobra Head	50,000*	0.471	17.38
455	Directional	16,000	0.181	$13.77
456	Directional	50,000*	0.471	18.21
457	Open Bottom	9,500	0.117	$10.86
Metal Halide				
470	Directional	12,000	0.150	$12.79
473	Directional	32,000	0.350	18.68
476	Directional	107,800*	1.080	39.60

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.

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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
High Pressure Sodium				
452	Cobra Head	16,000	0.181	$13.20
453	Cobra Head	28,500	0.294	15.52
454	Cobra Head	50,000*	0.471	17.89
455	Directional	16,000	0.181	$14.18
456	Directional	50,000*	0.471	18.75
457	Open Bottom	9,500	0.117	$11.18
Metal Halide				
470	Directional	12,000	0.150	$13.17
473	Directional	32,000	0.350	19.23
476	Directional	107,800*	1.080	40.77

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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Third Revision of Original Sheet No. 35.1
Canceling P.S.C. Electric No. 9, Second Revision of Original Sheet No. 35.1

Standard Rate **LS**
Lighting Service

Where the location of existing poles is not suitable or where there are no existing poles for mounting of lights, and customer requests service under these conditions, Company may furnish the requested facilities at an additional charge to be determined under the Excess Facilities Rider. For poles installed prior to 8/1/2010, such charge for each pole and span of secondary installed after 6/30/2004 and used in providing a light offered under LS as listed under RLS Sheet No. 36, Bill Code 958, and such charge for each pole and span of secondary installed prior to 6/30/2004 and used in providing a light offered under LS as listed under RLS Sheet No. 36, Bill Code 900.

UNDERGROUND SERVICE

Based on Customer's lighting choice, Company will furnish, own, install, and maintain poles, fixtures, and any necessary circuitry up to 200 feet. All poles and fixtures furnished by Company will be standard stocked materials. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for underground installation.

RATE

				Monthly Charge		
Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Fixture Only**	**Decorative Smooth**	**Historic Fluted**
High Pressure Sodium						
412	Colonial, 4-Sided	5,800	0.083		$19.79	
413	Colonial, 4-Sided	9,500	0.117		20.49	
415	Acorn	5,800	0.083		$20.18	
416	Acorn	9,500	0.117		22.56	
427	London	5,800	0.083			$35.20
429	London	9,500	0.117			36.07
431	Victorian	5,800	0.083			$32.93
433	Victorian	9,500	0.117			34.99
956	Victorian/London Bases					Westchester/Norfolk $ 3.56
423	Cobra Head	16,000	0.181		$26.35	
424	Cobra Head	28,500	0.294		28.45	
425	Cobra Head	50,000*	0.471		34.03	
439/420	Contemporary	16,000	0.181	$16.46	$29.89	
440/421	Contemporary	28,500*	0.294	18.28	32.86	
441/422	Contemporary	50,000*	0.471	22.32	38.39	

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 35.1

Standard Rate **LS**
Lighting Service

Where the location of existing poles is not suitable or where there are no existing poles for
mounting of lights, and customer requests service under these conditions, Company may furnish
the requested facilities at an additional charge to be determined under the Excess Facilities Rider.
For wood poles installed prior to 3/1/2010, such charge will be in accordance with the rates listed T
on Sheet No, 36.1 of the Restricted Lighting Service Rate RLS Tariff. T

UNDERGROUND SERVICE

Based on Customer's lighting choice, Company will furnish, own, install, and maintain poles, fixtures, and any necessary circuitry up to 200 feet. All poles and fixtures furnished by Company will be standard stocked materials. Company may decline to install equipment and provide service thereto in locations deemed by Company as unsuitable for underground installation.

RATE

				Monthly Charge		
Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Decorative Smooth**	**Historic Fluted**	T T
High Pressure Sodium						
412	Colonial, 4-Sided	5,800	0.083	$20.37		I
413	Colonial, 4-Sided	9,500	0.117	21.09		I
444	Colonial, 4-Sided	16,000	0.181	21.34		T/N
415	Acorn	5,800	0.083	$20.78		I
416	Acorn	9,500	0.117	23.23		I
445	Acorn	16,000	0.181	23.34		T/N
427	London	5,800	0.083		$36.24	I
429	London	9,500	0.117		37.13	I
431	Victorian	5,800	0.083		$33.90	I
433	Victorian	9,500	0.117		36.02	I
400	Dark Sky	4,000	0.060	$24.59		T/I
401	Dark Sky	9,500	0.117	25.63		T/I
956	Victorian/London Bases				Westchester/Norfolk $ 3.67	I
423	Cobra Head	16,000	0.181	$27.13		I
424	Cobra Head	28,500	0.294	29.29		I
425	Cobra Head	50,000*	0.471	35.03		I

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Third Revision of Original Sheet No. 35.2
Canceling P.S.C. Electric No. 9, Second Revision of Original Sheet No. 35.2

Standard Rate **LS**
Lighting Service

UNDERGROUND SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	 Decorative Smooth	 Historic Fluted
High Pressure Sodium						
400	Dark Sky	4,000	0.060		$23.89	
401	Dark Sky	9,500	0.117		24.90	
Metal Halide						
479/480	Contemporary	12,000	0.150	$14.06	$23.83	
481/482	Contemporary	32,000	0.350	20.46	30.21	
483/484	Contemporary	107,800*	1.080	42.56	52.31	

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
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 35.2

Standard Rate **LS**
Lighting Service

UNDERGROUND SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	 Decorative Smooth	
						T T
High Pressure Sodium						
439/420	Contemporary	16,000	0.181	$16.95	$30.77	T/I
440/421	Contemporary	28,500*	0.294	18.82	33.83	T/I
441/422	Contemporary	50,000*	0.471	22.98	39.52	T/I
Metal Halide						
479/480	Contemporary	12,000	0.150	$14.47	$24.53	I
481/482	Contemporary	32,000	0.350	21.06	31.10	I
483/484	Contemporary	107,800*	1.080	43.82	53.85	I

Customer shall make a non-refundable cash contribution prior to the time of installation, or, at the option of company, make a work contribution to Company for the difference in the installed cost of the system requested and the cost of the conventional overhead lighting system.

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.

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Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 35.3
Canceling P.S.C. Electric No. 9, Original Sheet No. 35.3

Standard Rate **LS**
Lighting Service

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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 35.3

Standard Rate **LS**
Lighting Service

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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Third Revision of Original Sheet No. 36
Canceling P.S.C. Electric No. 9, Second 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 August 1, 2012, except where a spot replacement maintains the continuity of multiple fixtures/poles composing a neighborhood lighting system. Spot placement of restricted fixtures/poles is contingent on the restricted fixtures/poles being available from manufacturers. Spot replacement of restricted units will be made under the terms and conditions provided for under non-restricted Lighting Service Rate LS.

In the event restricted fixtures/poles fail and replacements are unavailable, Customer will be given the choice of having Company remove the failed fixture/pole or replacing the failed fixture/pole with other available fixture/pole

OVERHEAD SERVICE

Based on Customer's lighting choice, Company has furnished, installed, and maintained the lighting unit complete with lamp, fixture, photoelectric control, mast arm, and, if needed, up to 150 feet of conductor per fixture on existing wood poles (fixture only).

RATE

				Monthly Charge		
Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Fixture Only**	**Fixture & Wood Pole**	**Fixture & Orn. Pole**
Mercury Vapor						
252	Cobra/Open Bottom	8,000	0.210	$ 9.57		
458	Cobra Head	8,000	0.210	$11.13		
203	Cobra Head	13,000	0.298	10.96		
204	Cobra Head	25,000	0.462	13.51		
209	Cobra Head	60,000	1.180	27.69		
207	Directional	25,000	0.462	$15.54		
210	Directional	60,000	1.180	28.89		
201	Open Bottom	4,000	0.100	$ 8.14		
Metal Halide						
471	Directional	12,000	0.150		$15.07	N/A
474/475	Directional	32,000	0.350		20.97	28.42
477	Directional	107,800	1.080		42.78	N/A

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: */s/* Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 T
fixtures/poles composing a neighborhood lighting system or continuity is desired for a T
subdivision being developed in phases. Spot placement of restricted fixtures/poles is T
contingent on the restricted fixtures/poles being available from manufacturers. Spot replacement of restricted units will be made under the terms and conditions provided for under non-restricted Lighting Service Rate LS.

In the event restricted fixtures/poles fail and replacements are unavailable, Customer will be given the choice of having Company remove the failed fixture/pole or replacing the failed fixture/pole with other available fixture/pole

OVERHEAD SERVICE

Based on Customer's lighting choice, Company has furnished, installed, and maintained the lighting unit complete with lamp, fixture, photoelectric control, mast arm, and, if needed, up to 150 feet of conductor per fixture on existing wood poles (fixture only).

RATE

				Monthly Charge			
Rate Code	**Type of Fixture**	**Approximate Lumens**	**kW Per Light**	**Fixture Only**	**Fixture & Wood Pole**	**Fixture & Orn. Pole**	
Mercury Vapor							
252	Cobra/Open Bottom	8,000	0.210	$ 9.59			I
203	Cobra Head	13,000	0.298	11.28			T/I
204	Cobra Head	25,000	0.462	13.91			I
209	Cobra Head	60,000	1.180	28.51			
207	Directional	25,000	0.462	$16.00			
210	Directional	60,000	1.180	29.74			
201	Open Bottom	4,000	0.100	$ 8.38			
Metal Halide							
471	Directional	12,000	0.150		$15.51	N/A	I
474/475	Directional	32,000	0.350		21.59	29.26	I
477	Directional	107,800	1.080		44.04	N/A	I

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: */s/* Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Third Revision of Original Sheet No. 36.1
Canceling P.S.C. Electric No. 9, Second 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	 Fixture & Wood Pole	 Fixture & Orn. Pole
Wood Pole						
958	Installed Before 3/1/2010			$11.31		
900	Installed Before 7/1/2004			2.06		

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	 Decorative Smooth
High Pressure Sodium					
275	Cobra/Contemporary	16,000	0.181		$24.89
266	Cobra/Contemporary	28,500	0.294		27.34
267	Cobra Contemporary	50,000	0.471		31.40
276	Coach/Acorn	5,800	0.083		$14.17
274	Coach/Acorn	9,500	0.117		17.19
277	Coach/Acorn	16,000	0.181		22.15
279/278	Contemporary	120,000	1.000	$41.43	$72.55
417	Acorn, Bronze	9,500	0.117		$23.68
419	Acorn, Bronze	16,000	0.180		24.77
280	Victorian	5,800	0.083	$19.38	
281	Victorian	9,500	0.117	20.35	
282	London	5,800	0.083	$19.53	
283	London	9,500	0.117	20.82	

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 36.1

Standard Rate **RLS**
Restricted Lighting Service

OVERHEAD SERVICE (continued)

RATE			T
Rate Code		**Monthly Charge**	T T
Wood Pole			
958	Installed Before 3/1/2010	$11.64	I
900	Installed Before 7/1/2004	2.12	I

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	 Decorative Smooth	
High Pressure Sodium						
275	Cobra/Contemporary	16,000	0.181		$25.62	I
266	Cobra/Contemporary	28,500	0.294		28.15	
267	Cobra Contemporary	50,000	0.471		32.33	
276	Coach/Acorn	5,800	0.083		$14.59	
274	Coach/Acorn	9,500	0.117		17.70	
277	Coach/Acorn	16,000	0.181		22.80	
279/278	Contemporary	120,000	1.000	$42.65	$74.69	
417	Acorn, Bronze	9,500	0.117		$24.38	
419	Acorn, Bronze	16,000	0.180		25.50	
280	Victorian	5,800	0.083	$19.95		
281	Victorian	9,500	0.117	20.95		
282	London	5,800	0.083	$20.11		
283	London	9,500	0.117	21.43		

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Third Revision of Original Sheet No. 36.2
Canceling P.S.C. Electric No. 9, Second Revision of Original Sheet No. 36.2

Standard Rate **RLS**
Restricted Lighting Service

UNDERGROUND SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth
High Pressure Sodium					
426	London	5,800	0.083		$33.22
428	London	9,500	0.117		34.09
430	Victorian	5,800	0.083		32.26
432	Victorian	9,500	0.117		34.33
Victorian/London Bases					
950	Old Town				$ 3.47
951	Chesapeake				3.73
Poles					
901	10" Smooth Pole				10.81
902	10" Fluted Pole				12.90
Mercury Vapor					
318	Cobra Head	8,000	0.210		$17.42
314	Cobra Head	13,000	0.298		19.20
315	Cobra Head	25,000	0.462		22.95
347	Cobra (State of KY Pole)	25,000	0.462	$22.94	
206	Coach	4,000	0.100		$12.45
208	Coach	8,000	0.210		14.24
Incandescent					
349	Continental Jr.	1,500	0.102		$ 9.02
348	Continental Jr.	6,000	0.447		13.12

Where Customer's location required the installation of additional facilities, Company may have furnished the requested facilities at an additional charge per month to be determined under the Excess Facilities Rider.

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.

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 36.2

Standard Rate **RLS**
Restricted Lighting Service

UNDERGROUND SERVICE (continued)

RATE

Rate Code	Type of Fixture	Approximate Lumens	kW Per Light	Monthly Charge Fixture Only	Monthly Charge Decorative Smooth	
High Pressure Sodium						
426	London	5,800	0.083		$34.20	I
428	London	9,500	0.117		35.10	
430	Victorian	5,800	0.083		33.21	
432	Victorian	9,500	0.117		35.34	
Victorian/London Bases						
950	Old Town				$ 3.57	
951	Chesapeake				3.84	
Poles						
901	10" Smooth Pole				11.13	
902	10" Fluted Pole				13.28	
Mercury Vapor						
318	Cobra Head	8,000	0.210		$17.93	
314	Cobra Head	13,000	0.298		19.77	
315	Cobra Head	25,000	0.462		23.63	
347	Cobra (State of KY Pole)	25,000	0.462	$23.62		
206	Coach	4,000	0.100		$12.82	
208	Coach	8,000	0.210		14.66	
Incandescent						
349	Continental Jr.	1,500	0.102		$ 9.29	
348	Continental Jr.	6,000	0.447		13.51	

Where Customer's location required the installation of additional facilities, Company may have furnished the requested facilities at an additional charge per month to be determined under the Excess Facilities Rider.

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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 36.3
Canceling P.S.C. Electric No. 9, Original Sheet No. 36.3

Standard Rate **RLS**
Restricted Lighting Service

DETERMINATION OF ENERGY CONSUMPTION

The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice to the other when additional facilities are required. Cancellation by Customer prior to the initial five-year term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the original five (5) year term.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.

2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults. Company shall initiate service corrections within two (2) business days after such notification by Customer.

3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.

4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.

5. 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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 36.3

Standard Rate **RLS**
Restricted Lighting Service

DETERMINATION OF ENERGY CONSUMPTION

The kilowatt-hours will be determined as set forth on Sheet No. 67 of this Tariff.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

TERM OF CONTRACT

For a fixed term of not less than five (5) years and for such time thereafter until terminated by either party giving thirty (30) days prior written notice to the other when additional facilities are required. Cancellation by Customer prior to the initial five-year term will require Customer to pay to Company a lump sum equal to the monthly charge times the number of months remaining on the original five (5) year term.

TERMS AND CONDITIONS

1. Service shall be furnished under Company's Terms and Conditions, except as set out herein.

2. All service and maintenance will be performed only during regular scheduled working hours of Company. Customer will be responsible for reporting outages and other operating faults. Company shall initiate service corrections within two (2) business days after such notification by Customer.

3. Customer shall be responsible for the cost of fixture replacement or repairs where such replacement or repairs are caused from willful damage, vandalism, or causes other than normal burnouts. Company may decline to provide or continue service in locations where, in Company's judgment, such facilities will be subject to unusual hazards or risk of damage.

4. Company shall have the right to make other attachments and to further extend the conductors, when necessary, for the further extension of its electric service.

5. 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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Second Revision of Original Sheet No. 37
Canceling P.S.C. Electric No. 9, First Revision of Original Sheet No. 37

Standard Rate **LE**
Lighting Energy Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available to municipalities, county governments, divisions or agencies of the state or Federal governments, civic associations, and other public or quasi-public agencies for service to public street and highway lighting systems, where the municipality or other agency owns and maintains all street lighting equipment and other facilities on its side of the point of delivery of the energy supplied hereunder.

RATE
$0.06461 per kWh

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL
Customer's payment will be due within 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: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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
$0.06661 per kWh I

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL
Customer's payment will be due within 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: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Third Revision of Original Sheet No. 38
Canceling P.S.C. Electric No. 9, Second Revision of Original Sheet No. 38

Standard Rate **TE**
Traffic Energy Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to municipalities, county governments, divisions of the state or Federal governments or any other governmental agency for service on a 24-hour all-day every-day basis, where the governmental agency owns and maintains all equipment on its side of the point of delivery of the energy supplied hereunder. In the application of this rate each point of delivery will be considered as a separate customer.

This service is limited to traffic control devices including, signals, cameras, or other traffic lights and electronic communication devices.

RATE

Basic Service Charge: $3.25 per delivery per month

Plus an Energy Charge of: $0.07658 per kWh

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 38

Standard Rate **TE**
Traffic Energy Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to municipalities, county governments, divisions of the state or Federal governments or any other governmental agency for service on a 24-hour all-day every-day basis, where the governmental agency owns and maintains all equipment on its side of the point of delivery of the energy supplied hereunder. In the application of this rate each point of delivery will be considered as a separate customer.

This service is limited to traffic control devices including, signals, cameras, or other traffic lights and electronic communication devices.

RATE

Basic Service Charge: $4.00 per delivery per month I

Plus an Energy Charge of: $0.07659 per kWh I

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 38.1

Standard Rate **TE**

Traffic Energy Service

CONDITIONS OF SERVICE

1. Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption, taking into account the size and characteristics of the load, or on meter readings obtained from a similar installation.

2. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and the customer. Where attachment of Customer's devices is made to Company facilities, Customer must have an attachment agreement with Company.

3. Loads not operated on an all-day every-day basis will be served under the appropriate rate.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 38.1

Standard Rate **TE**

Traffic Energy Service

CONDITIONS OF SERVICE

1. Service hereunder will be metered except when, by mutual agreement of Company and customer, an unmetered installation will be more satisfactory from the standpoint of both parties. In the case of unmetered service, billing will be based on a calculated consumption, taking into account the size and characteristics of the load, or on meter readings obtained from a similar installation.

2. The location of each point of delivery of energy supplied hereunder shall be mutually agreed upon by Company and the customer. Where attachment of Customer's devices is made to Company facilities, Customer must have an attachment agreement with Company.

3. Loads not operated on an all-day every-day basis will be served under the appropriate rate.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 40

Standard Rate **CTAC**
Cable Television Attachment Charges

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Where Company is willing to permit the attachments of cables, wires and appliances to its poles where, in Company's judgment, such attachments will not interfere with its electric service requirements and other prior licensees using Company's poles. Attachments will be permitted upon execution by both parties of a Cable Television Attachment Agreement supplied by Company.

ATTACHMENT CHARGE
$9.11 per year for each attachment to pole.

BILLING
Attachment Charges to be billed semi-annually based on the number of pole attachments being maintained on December 1 and June 1. Provided, however, that should the Agreement be terminated in accordance with the terms of the said Agreement, the Attachment Charges will be prorated to the date of such termination. Payment will be due within thirty (30) days from date of bill. Non-payment of bills shall constitute a default of the Agreement.

TERM OF AGREEMENT
The Cable Television Attachment Agreement shall become effective upon execution by both parties and shall continue in effect for not less than one (1) year, subject to provisions contained in the agreement. At any time thereafter, the Customer may terminate the agreement by giving not less than six (6) months' prior written notice. Upon termination of the agreement, Customer shall immediately remove its cables, wire, appliances and all other attachments from all poles of Company.

TERMS AND CONDITIONS OF POLE ATTACHMENTS
Pole attachments shall be permitted in accordance with this Schedule. Company's Terms and Conditions shall be applicable, to the extent they are not in conflict with or inconsistent with, the special provisions of this Schedule.

Upon written Agreement, Company is willing to permit, to the extent it may lawfully do so, the attachment of cables, wires and appliances to its poles by a cable television system operator, hereinafter "Customer," where, in its judgment, such use will not interfere with its electric service requirements and other prior licensees using Company's poles, including consideration of economy and safety, in accordance with this schedule approved by the Public Service Commission. The Terms and Conditions applicable to such service are as follows:

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 40

Standard Rate **CTAC**
Cable Television Attachment Charges

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Where Company is willing to permit the attachments of cables, wires and appliances to its poles where, in Company's judgment, such attachments will not interfere with its electric service requirements and other prior licensees using Company's poles. Attachments will be permitted upon execution by both parties of a Cable Television Attachment Agreement supplied by Company.

ATTACHMENT CHARGE
$9.11 per year for each attachment to pole.

BILLING
Attachment Charges to be billed semi-annually based on the number of pole attachments being maintained on December 1 and June 1. Provided, however, that should the Agreement be terminated in accordance with the terms of the said Agreement, the Attachment Charges will be prorated to the date of such termination. Payment will be due within thirty (30) days from date of bill. Non-payment of bills shall constitute a default of the Agreement.

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Upon written Agreement, Company is willing to permit, to the extent it may lawfully do so, the attachment of cables, wires and appliances to its poles by a cable television system operator, hereinafter "Customer," where, in its judgment, such use will not interfere with its electric service requirements and other prior licensees using Company's poles, including consideration of economy and safety, in accordance with this schedule approved by the Public Service Commission. The Terms and Conditions applicable to such service are as follows:

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 40.1
Canceling P.S.C. Electric No. 9, Original Sheet No. 40.1

Standard Rate **CTAC**

Cable Television Attachment Charges

1. **ATTACHMENT APPLICATIONS AND PERMITS**
   Before making attachment to any pole or poles of Company, Customer shall make application and receive a permit therefore on a form to be supplied by Company. The information submitted by Customer with the application for a permit shall consist of drawings and associated descriptive matter which shall be adequate in all detail to enable Company to thoroughly check the proposed installation of Customer. Before the attachments are made, the permit must be approved by Company. Customer shall not build separate pole lines along existing facilities of Company and shall not place intermediate poles in spans of Company, unless authorized by Company in writing. Company shall have the right to remove unauthorized Customer attachments at Customer's expense after notice to Customer. In the event a pole attachment count does not correspond to the recorded attachment count, Customer will pay a back attachment fee for any excess attachments. The back attachment fee will be double the rate otherwise in effect over the time since last pole attachment count and shall be payable on demand.

2. **PERMITTED ATTACHMENTS**
   Customer shall be permitted to make only one bolt attachment for one messenger on tangent poles and two bolt attachments for two messengers on corner poles. A maximum of five individual coaxial cables may be supported by any single messenger if these cables are all attached to the messenger by suitable lashings or bindings, and so that the maximum overall dimension of the resulting cable bundle does not exceed two (2) inches. Any messenger attachment other than to tangent poles must be properly braced with guys and anchors provided by Customer to the satisfaction of Company. The use of existing Company anchors for this purpose must be specifically authorized in writing, subject to additional charge, and will not ordinarily be permitted. The use of crossarms or brackets shall not be permitted. In addition to messenger attachments, Customer will be permitted one Customer amplifier installation per pole and four service drops to be tapped on cable messenger strand and not on pole. Customer power supply installations shall be permitted, but only at pole locations specifically approved by Company. Any or all of the above are considered one attachment for billing purposes. Any additional attachments desired by Customer will be considered on an individual basis by Company, and as a separate attachment application.

3. **CONSTRUCTION AND MAINTENANCE REQUIREMENTS AND SPECIFICATIONS**
   Customer's cables, wires and appliances, in each and every location, shall be erected and maintained in accordance with the requirements and specifications of the National Electrical Safety Code, current edition, and Company's construction practices, or any amendments or revisions of said Code and in compliance with any rules or orders now in effect or that hereinafter may be issued by the Public Service Commission of Kentucky, or other authority having jurisdiction. In the event any of Customer's construction does not meet any of the foregoing requirements, Customer will correct same in fifteen work days after written notification. Company may make corrections and bill Customer for total costs incurred, if not corrected by Customer.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 40.1

Standard Rate **CTAC**

Cable Television Attachment Charges

1. **ATTACHMENT APPLICATIONS AND PERMITS**
   Before making attachment to any pole or poles of Company, Customer shall make application and receive a permit therefore on a form to be supplied by Company. The information submitted by Customer with the application for a permit shall consist of drawings and associated descriptive matter which shall be adequate in all detail to enable Company to thoroughly check the proposed installation of Customer. Before the attachments are made, the permit must be approved by Company. Customer shall not build separate pole lines along existing facilities of Company and shall not place intermediate poles in spans of Company, unless authorized by Company in writing. Company shall have the right to remove unauthorized Customer attachments at Customer's expense after notice to Customer. In the event a pole attachment count does not correspond to the recorded attachment count, Customer will pay a back attachment fee for any excess attachments. The back attachment fee will be double the rate otherwise in effect over the time since last pole attachment count and shall be payable on demand.

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State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 40.2
Canceling P.S.C. Electric No. 9, Original Sheet No. 40.2

Standard Rate **CTAC**
Cable Television Attachment Charges

4. **MAINTENANCE OF ATTACHMENTS**
Customer shall, at its own expense, make and maintain said attachments in safe condition and in thorough repair, and in a manner suitable to Company and so as not to conflict with the use of said poles by Company, or by other parties, firms, corporations, governmental units, etc., using said poles, pursuant to any license or permit by Company, or interfere with the working use of facilities thereon or which may, from time to time, be placed thereon. Customer shall promptly at any time, at its own expense, upon written notice from Company, relocate, replace or renew its facilities placed on said poles, and transfer them to substituted poles, or perform any other work in connection with said facilities that may be required by Company but in no case longer than 30 day after date of written request. In cases of emergency, however, Company may arrange to relocate, replace or renew the facilities placed on said poles by Customer, transfer them to substituted poles or perform any other work in connection with said facilities that may be required in the maintenance, replacement, removal or relocation of said poles, the facilities thereon or which may be placed thereon, or for the service needs of Company, or its other licensees, and Customer shall, on demand, reimburse Company for the expense thereby incurred.

5. **COSTS ASSOCIATED WITH ATTACHMENTS**
In the event that any pole or poles of Company to which Customer desires to make attachments are inadequate to support the additional facilities in accordance with the aforesaid specifications, Company will indicate on the application and permit form the changes necessary to provide adequate poles and the estimated cost thereof to Customer. If Customer still desires to make the attachments, Company will replace such inadequate poles with suitable poles and Customer will, on demand, reimburse Company for the total cost of pole replacement necessary to accommodate Customer attachments, less the salvage value of any pole that is removed, and the expense of transferring Company's facilities from the old to the new poles. Where Customer desired attachments can be accommodated on present poles of Company by rearranging Company's facilities thereon, Customer will compensate Company for the full expense incurred in completing such rearrangements, within ten days after receipt of Company's invoice for such expense. Customer will also, on demand, reimburse the owner or owners of other facilities attached to said poles for any expense incurred by it or them in transferring or rearranging said facilities. In the event Customer makes an unauthorized attachment which necessitates rearrangements when discovered, then Customer shall pay on demand twice the expense incurred in completing such rearrangements.

6. **MAINTENANCE AND OPERATION OF COMPANY'S FACILITIES**
Company reserves to itself, its successors and assigns, the right to maintain its poles and to operate its facilities thereon in such manner as will, in its own judgment, best enable it to fulfill its electric service requirements, but in accordance with the specifications herein before referred to. Company shall not be liable to Customer for any interruption to service to Customer's subscribers or for interference with the operation of the cables, wires and appliances of Customer arising in any manner out of the use of Company's poles hereunder.

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 40.2

Standard Rate **CTAC**
Cable Television Attachment Charges

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Standard Rate **CTAC**
Cable Television Attachment Charges

7. **FRANCHISES AND EASEMENTS**
Customer shall submit to Company evidence, satisfactory to Company, of Customer’s authority to erect and maintain Customer’s facilities within public streets, highways and other thoroughfares within the above described territory which is to be served and shall secure any necessary consent by way of franchise or other satisfactory license, permit or authority, acceptable to Company from State, County or municipal authorities or from the owners of property where necessary to construct and maintain facilities at the locations of poles of Company which it desires to use. Customer must secure its own easement rights on private property. Customer must, regardless of authority received or franchises given by governmental agencies, conform to all requirements of Terms and Conditions with regard to Company’s property. Company’s approval of attachments shall not constitute any representation or warranty by Company to Customer regarding Customer’s right to occupy or use any public or private right-of-way.

8. **INSPECTION OF FACILITIES**
Company reserves the right to inspect each new installation of Customer on its poles and in the vicinity of its lines or appliances and to make periodic inspections, every two (2) years or more often as plant conditions warrant of the entire plant of Customer. Such inspections, made or not, shall not operate to relieve Customer of any responsibility, obligation or liability.

9. **PRECAUTIONS TO AVOID FACILITY DAMAGE**
Customer shall exercise precautions to avoid damage to facilities of Company and of others supported on said poles; and shall assume all responsibility of any and all loss for such damage caused by it. Customer shall make an immediate report to Company of the occurrence of any damage and shall reimburse Company for the expense incurred in making repairs.

10. **INDEMNITIES AND INSURANCE**
Customer shall defend, indemnify and save harmless Company from any and all damage, loss, claim, demand, suit, liability, penalty or forfeiture of every kind and nature-including but not limited to costs and expenses of defending against the same and payment of any settlement or judgment therefore, by reason of (a) injuries or deaths to persons, (b) damages to or destructions of properties, (c) pollutions, contaminations of or other adverse effects on the environment or (d) violations of governmental laws, regulations or orders whether suffered directly by Company it-self or indirectly by reason of claims, demands or suits against it by third parties, resulting or alleged to have resulted from acts or omissions of Customer, its employees, agents, or other representatives or from their presence on the premises of Company, either solely or in concurrence with any alleged joint negligence of Company.

Customer shall provide and maintain in an Insurance Company(s) authorized to do business in the Commonwealth of Kentucky, the following:

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Cable Television Attachment Charges

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2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 40.4
Canceling P.S.C. Electric No. 9, Original Sheet No. 40.4

Standard Rate **CTAC**
Cable Television Attachment Charges

(a) Insurance protection for Customer employees to the extent required by the Workmen's Compensation Law of Kentucky and, where same is not applicable or if necessary to provide a defense for Company, Employer's Liability Protection (covering both Company and Customer) for Customer employees for no less than $100,000.00 per employee.

(b) Public Liability and Business Liability insurance with a minimum limit of $500,000.00 for each person injured and with a minimum total limit of $1,000,000.00 for each accident and a minimum limit of $100,000.00 for property damage for each accident.

(c) Public Liability and Property Damage insurance on all automotive equipment used by Customer on job to the extent of the amounts for Public Liability and Property Damage insurance set out in the preceding Paragraph (b).

(d) In the event that work covered by the Agreement includes work to be done in places or areas where the Maritime Laws are in effect, then and in that event additional insurance protection to the limits in Paragraph (b) above for liability arising out of said Maritime Laws.

e) In the event the work covers fixed wing aircraft, rotor lift, lighter than air aircraft or any other form of aircraft, appropriate insurance will be carried affording protection to the limits prescribed in the preceding Paragraph (b).

(f) In the event the work covers blasting, explosives or operations underground, in trenches or other excavations, appropriate insurance will be carried affording protection to the limits prescribed in the preceding Paragraph (b), together with products hazard and completed operations insurance where applicable, affording protection to the limits above prescribed. Customer's liability insurance shall be written to eliminate XCU exclusions. Said insurance is to be kept in force for not less than one year after cancellation of the Agreement.

Before starting work, Customer shall furnish to Company a certificate(s) of insurance satisfactory to Company, evidencing the existence of the insurance required by the above provisions, and this insurance may not be canceled for any cause without sixty (60) days advance written notice being first given Company; provided, that failure of Company to require Customer to furnish any such certificate(s) shall not constitute a waiver by Company of Customer's obligation to maintain insurance as provided herein.

Each policy required hereunder shall contain a contractual endorsement written as follows: "The insurance provided herein shall also be for the benefit of Louisville Gas and Electric Company so as to guarantee, within the policy limits, the performance by the named insured of the indemnity provisions of the Cable Television Attachment Agreement between the named insured and Louisville Gas and Electric Company. This insurance may not be canceled for any cause without sixty (60) days advance written notice being first given to Louisville Gas and Electric Company."

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Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 40.4

Standard Rate **CTAC**
Cable Television Attachment Charges

(a) Insurance protection for Customer employees to the extent required by the Workmen's Compensation Law of Kentucky and, where same is not applicable or if necessary to provide a defense for Company, Employer's Liability Protection (covering both Company and Customer) for Customer employees for no less than $100,000.00 per employee.

(b) Public Liability and Business Liability insurance with a minimum limit of $500,000.00 for each person injured and with a minimum total limit of $1,000,000.00 for each accident and a minimum limit of $100,000.00 for property damage for each accident.

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(d) In the event that work covered by the Agreement includes work to be done in places or areas where the Maritime Laws are in effect, then and in that event additional insurance protection to the limits in Paragraph (b) above for liability arising out of said Maritime Laws.

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Standard Rate **CTAC**

Cable Television Attachment Charges

11. ATTACHMENT REMOVAL AND NOTICES

Customer may at any time voluntarily remove its attachments from any pole or poles of Company, but shall immediately give Company written notice of such removal on a form to be supplied by Company. No refund of any attachment charge will be due on account of such voluntary removal.

12. FORBIDDEN USE OF POLES

Prior to Customer’s initial attachment, Company reserves the right due to engineering design requirements to refuse use by Customer of certain or specific poles or structures (such as normal transmission routes). Upon notice from Company to Customer that the use of any pole or poles is forbidden by municipal or other public authorities or by property owners, the permit covering the use of such pole or poles shall immediately terminate and Customer shall remove its facilities from the affected pole or poles at once. No refund of any attachment charge will be due on account of any removal resulting from such forbidden use.

13. NON-COMPLIANCE

If Customer shall fail to comply with any of the provisions of these Rules and Regulations or Terms and Conditions or default in any of its obligations under these Rules and Regulations or Terms and Conditions and shall fail within thirty (30) days after written notice from Company to correct such default or non-compliance, Company may, at its option, forthwith terminate the Agreement or the permit covering the poles as to which such default or non- compliance shall have occurred, by giving written notice to Customer of said termination. No refund of any rental will be due on account of such termination.

14. WAIVERS

Failure to enforce or insist upon compliance with any of these Rules and Regulations or Terms and Conditions or the Agreement shall not constitute a general waiver or relinquishment thereof, but the same shall be and remain at all times in full force and effect.

15. USE OF COMPANY’S FACILITIES BY OTHERS

Nothing herein contained shall be construed as affecting the rights or privileges previously conferred by Company, by contract or otherwise, to others, not parties to the Agreement, to use any poles covered by the Agreement; and Company shall have the right to continue and to extend such rights or privileges. The attachment privileges herein granted shall at all times be subject to such existing contracts and arrangements.

16. ASSIGNMENT

Customer shall not assign, transfer or sublet the privileges hereby granted and/or provided in the Agreement without the prior consent in writing of Company.

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Customer may at any time voluntarily remove its attachments from any pole or poles of Company, but shall immediately give Company written notice of such removal on a form to be supplied by Company. No refund of any attachment charge will be due on account of such voluntary removal.

12. FORBIDDEN USE OF POLES

Prior to Customer’s initial attachment, Company reserves the right due to engineering design requirements to refuse use by Customer of certain or specific poles or structures (such as normal transmission routes). Upon notice from Company to Customer that the use of any pole or poles is forbidden by municipal or other public authorities or by property owners, the permit covering the use of such pole or poles shall immediately terminate and Customer shall remove its facilities from the affected pole or poles at once. No refund of any attachment charge will be due on account of any removal resulting from such forbidden use.

13. NON-COMPLIANCE

If Customer shall fail to comply with any of the provisions of these Rules and Regulations or Terms and Conditions or default in any of its obligations under these Rules and Regulations or Terms and Conditions and shall fail within thirty (30) days after written notice from Company to correct such default or non-compliance, Company may, at its option, forthwith terminate the Agreement or the permit covering the poles as to which such default or non- compliance shall have occurred, by giving written notice to Customer of said termination. No refund of any rental will be due on account of such termination.

14. WAIVERS

Failure to enforce or insist upon compliance with any of these Rules and Regulations or Terms and Conditions or the Agreement shall not constitute a general waiver or relinquishment thereof, but the same shall be and remain at all times in full force and effect.

15. USE OF COMPANY’S FACILITIES BY OTHERS

Nothing herein contained shall be construed as affecting the rights or privileges previously conferred by Company, by contract or otherwise, to others, not parties to the Agreement, to use any poles covered by the Agreement; and Company shall have the right to continue and to extend such rights or privileges. The attachment privileges herein granted shall at all times be subject to such existing contracts and arrangements.

16. ASSIGNMENT

Customer shall not assign, transfer or sublet the privileges hereby granted and/or provided in the Agreement without the prior consent in writing of Company.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 40.6
Canceling P.S.C. Electric No. 9, Original Sheet No. 40.6

Standard Rate **CTAC**
Cable Television Attachment Charges

17. PROPERTY RIGHTS

No use, however extended, of Company poles under the Agreement shall create or vest in Customer any ownership or property rights in said poles, but Customer shall be and remain a customer only. Nothing herein contained shall be construed to compel Company to maintain any of said poles for a period longer than demanded by its electric service requirements.

18. FAILURE TO PROCEED

Customer agrees to proceed as expeditiously as practical with the work of providing the television cable service to the area described in the Agreement. Within ninety (90) days from the date of the Agreement, Customer shall make progress reasonably satisfactory to Company in the installation of its facilities or shall demonstrate, to the reasonable satisfaction of Company, its ability to proceed expeditiously.

19. TERMINATION

Upon termination of the Agreement in accordance with any of its terms, Customer shall immediately remove its cables, wires and appliances from all poles of Company. If not removed, Company shall have the right to remove them at the cost and expense of Customer.

20.SECURITY

Customer shall furnish bond for the purposes hereinafter specified as follows:

(a) during the period of Customer's initial installation of its facilities and at the time of any expansion involving more than seventy-five (75) poles, a bond in the amount of $2,000 for each 100 poles (or fraction thereof) to which Customer intends to attach its facilities;
(b) following the satisfactory completion of Customer's initial installation, the amount of bond shall be reduced to $1,000 for each 100 poles (or fraction thereof);
(c) after Customer has been a customer of Company pursuant to the Agreement and is not in default thereunder for a period of three years, the bond shall be reduced to $500 for each 100 poles (or fraction thereof).
(d) such bond shall contain the provision that it shall not be terminated prior to six (6) months after receipt by Company of written notice of the desire of the bonding or insurance company to terminate such bond. This six (6) months' termination clause may be waived by Company if an acceptable replacement bond is received before the six (6) months has ended. Upon receipt of such termination notice, Company shall request Customer to immediately remove its cables, wires and all other facilities from all poles of Company. If Customer should fail to complete the removal of all of its facilities from the poles of Company within thirty (30) days after receipt of such request from Company, then Company shall have the right to remove them at the cost and expense of Customer and without being liable for any damage to Customer's wires, cables, fixtures or appurtenances. Such bond shall guarantee the payment of any sums which may become due to Company for rentals, inspections or work performed for the benefit of Customer under the Agreement, including the removal of attachments upon termination of the Agreement by any of its provisions.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 40.6

Standard Rate **CTAC**
Cable Television Attachment Charges

17. PROPERTY RIGHTS

No use, however extended, of Company poles under the Agreement shall create or vest in Customer any ownership or property rights in said poles, but Customer shall be and remain a customer only. Nothing herein contained shall be construed to compel Company to maintain any of said poles for a period longer than demanded by its electric service requirements.

18. FAILURE TO PROCEED

Customer agrees to proceed as expeditiously as practical with the work of providing the television cable service to the area described in the Agreement. Within ninety (90) days from the date of the Agreement, Customer shall make progress reasonably satisfactory to Company in the installation of its facilities or shall demonstrate, to the reasonable satisfaction of Company, its ability to proceed expeditiously.

19. TERMINATION

Upon termination of the Agreement in accordance with any of its terms, Customer shall immediately remove its cables, wires and appliances from all poles of Company. If not removed, Company shall have the right to remove them at the cost and expense of Customer.

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Customer shall furnish bond for the purposes hereinafter specified as follows:

(a) during the period of Customer's initial installation of its facilities and at the time of any expansion involving more than seventy-five (75) poles, a bond in the amount of $2,000 for each 100 poles (or fraction thereof) to which Customer intends to attach its facilities;
(b) following the satisfactory completion of Customer's initial installation, the amount of bond shall be reduced to $1,000 for each 100 poles (or fraction thereof);
(c) after Customer has been a customer of Company pursuant to the Agreement and is not in default thereunder for a period of three years, the bond shall be reduced to $500 for each 100 poles (or fraction thereof).
(d) such bond shall contain the provision that it shall not be terminated prior to six (6) months after receipt by Company of written notice of the desire of the bonding or insurance company to terminate such bond. This six (6) months' termination clause may be waived by Company if an acceptable replacement bond is received before the six (6) months has ended. Upon receipt of such termination notice, Company shall request Customer to immediately remove its cables, wires and all other facilities from all poles of Company. If Customer should fail to complete the removal of all of its facilities from the poles of Company within thirty (30) days after receipt of such request from Company, then Company shall have the right to remove them at the cost and expense of Customer and without being liable for any damage to Customer's wires, cables, fixtures or appurtenances. Such bond shall guarantee the payment of any sums which may become due to Company for rentals, inspections or work performed for the benefit of Customer under the Agreement, including the removal of attachments upon termination of the Agreement by any of its provisions.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Standard Rate **CTAC**

Cable Television Attachment Charges

e) Company in its sole discretion may agree in writing to accept other collateral (such as a cash deposit or an irrevocable bank letter of credit) in substitution for the bond required by, and subject to the other requirements of, this Section 20.

21. NOTICES

Any notice, or request, required by these Rules and Regulations or Terms and Conditions or the Agreement shall be deemed properly given if mailed, postage pre-paid, to Company, in the case of Company; or in the case of the Customer, to its representative designated in the Agreement. The designation of the person to be notified, and/or his address may be changed by Company or Customer at any time, or from time to time, by similar notice.

22. ADJUSTMENTS

Nothing contained herein or in any Agreement shall be construed as affecting in any way the right of Company, and Company shall at all times have the right, to unilaterally file with the Public Service Commission a change in rental charges for attachments to poles, other charges as provided for, any rule, regulation, condition or any other change required. Such change or changes to become effective upon approval of the Commission or applicable regulations or statutes, and shall constitute an amendment to the Agreement.

23. BINDING EFFECT

Subject to the provisions of Section 16 hereof, the Agreement and these Rules and Regulations or Terms and Conditions shall extend to and bind the successors and assigns of the parties hereto.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Standard Rate **CTAC**

Cable Television Attachment Charges

e) Company in its sole discretion may agree in writing to accept other collateral (such as a cash deposit or an irrevocable bank letter of credit) in substitution for the bond required by, and subject to the other requirements of, this Section 20.

21. NOTICES

Any notice, or request, required by these Rules and Regulations or Terms and Conditions or the Agreement shall be deemed properly given if mailed, postage pre-paid, to Company, in the case of Company; or in the case of the Customer, to its representative designated in the Agreement. The designation of the person to be notified, and/or his address may be changed by Company or Customer at any time, or from time to time, by similar notice.

22. ADJUSTMENTS

Nothing contained herein or in any Agreement shall be construed as affecting in any way the right of Company, and Company shall at all times have the right, to unilaterally file with the Public Service Commission a change in rental charges for attachments to poles, other charges as provided for, any rule, regulation, condition or any other change required. Such change or changes to become effective upon approval of the Commission or applicable regulations or statutes, and shall constitute an amendment to the Agreement.

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Second Revision of Original Sheet No. 45
Canceling P.S.C. Electric No. 9, First Revision of 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. If both gas and electric services are reconnected at the same time, the total charge for restoration of both services shall be $28.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 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.

METER DATA PROCESSING CHARGE

A charge of $2.75 per report will be made to cover the cost of processing, generating, and providing recorder metered customer with profile reports. If a customer is not recorder metered and desires to have such metering installed, the customer will pay all costs associated with installing the recorder meter.

DATE OF ISSUE: April 22, 2013

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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.

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 50
Canceling P.S.C. Electric No. 9, Original Sheet No. 50

Standard Rate Rider **CSR10**
Curtailable Service Rider 10

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to customers served under applicable power schedules who contract for not less than 1,000 kilowatts individually. The aggregate service under P.S.C. No. 9, CSR10 and CSR30 for Louisville Gas and Electric Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric Company as of August 1, 2010.

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed three hundred and seventy-five (375) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time that may have both physical curtailments and buy-through options within the interval between the start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than ten (10) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year without a buy-through option during system reliability events. For the purposes of this rider, a system reliability event is any condition or occurrence: 1) that impairs KU and LG&E's ability to maintain service to contractually committed system load; 2) where KU and LG&E ability to meet their compliance obligations with NERC reliability standards cannot otherwise be achieved; or 3) that KU and LG&E reasonably anticipate will last more than six hours and could require KU and LG&E to call upon automatic reserve sharing ("ARS") at some point during the event. Company may also request at its sole discretion up to 275 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements.

Curtailable load and compliance with a request for curtailment shall be measured in one of the following ways:

Option A -- Customer may contract for a given amount of firm demand, as measured on the demand basis of the standard rate on which Customer is billed. During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price, as applicable, shall apply to the difference in the actual kWh during any requested curtailment and the contracted firm demand multiplied by the time period (hours) of curtailment [Actual

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 50

Standard Rate Rider **CSR10**
Curtailable Service Rider 10

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to customers served under applicable power schedules who
contract for not less than 1,000 kVA individually. The aggregate service under CSR10 and T
CSR30 for Louisville Gas and Electric Company is limited to 100 MVA in addition to the T
contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric Company as
of August 1, 2010.

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification
by Company. Requests for curtailment shall not exceed one hundred (100) hours per year nor T
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 T
shall give no less than ten (10) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year. 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. T
During a request for physical curtailment, Customer shall reduce its demand to
the firm demand designated in the contract. 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.

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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 50.1
Canceling P.S.C. Electric No. 9, Original Sheet No. 50.1

Standard Rate Rider **CSR10**
Curtailable Service Rider 10

kWh – (firm kVA x hours curtailed)]. The measured demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance, as measured on the demand basis of the standard rate on which Customer is billed.

Option B -- Customer may contract for a given amount of curtailable load by which Customer shall agree to reduce its demand at any time by such Designated Curtailable Load. During a request for physical curtailment, Customer shall reduce its demand to a level equal to the maximum demand (as measured on the demand basis of the standard rate on which Customer is billed) immediately prior to the curtailment less the designated curtailable load. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price shall apply to the difference in the actual kWh during any requested curtailment and the product of Customer's maximum load immediately preceding curtailment less Customer's designated curtailable load designated in the contract multiplied by the time period (hours) of a requested curtailment {Actual kWh – [(Max kVA preceding – Designated Curtailable kVA) x hours of requested curtailment]}. Non-compliance for each requested physical curtailment shall be the measured positive value determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) the Customer's maximum demand during such curtailment.

RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service	$ 5.40 per kVA of Curtailable Billing Demand
Primary Voltage Service	$ 5.50 per kVA of Curtailable Billing Demand
Non-Compliance Charge of:	$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.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 50.1

Standard Rate Rider **CSR10**
Curtailable Service Rider 10

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RATE T

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service	$ 5.40 per kVA of Curtailable Billing Demand
Primary Voltage Service	$ 5.50 per kVA of Curtailable Billing Demand
Non-Compliance Charge of:	$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 T

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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 50.2
Canceling P.S.C. Electric No. 9, Original Sheet No. 50.2

Standard Rate Rider **CSR10**
Curtailable Service Rider 10

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 represents the mid-point price for natural gas ($/MMBtu) posted for the day in *Platts Gas Daily* for Dominion—South Point and will be used for the electrical day from 12 midnight to midnight. Also the posted price for Monday or the day after a holiday is the posted price for Saturday, Sunday and the holiday.

TERM OF CONTRACT

The minimum original contract period shall be one (1) year and thereafter until terminated by giving at least six (6) months previous written notice, but Company may require that contract be executed for a longer initial term when deemed reasonably necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

When the Company requests curtailment, upon request by the Customer, the Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by the Company, the Customer shall provide to the Company a good-faith, non-binding short-term operational schedule for their facility. Upon request by the Customer, the Company will provide, once per month, to the Customer an explanation of the reasons for any request for curtailment.

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 50.2

Standard Rate Rider **CSR10**
Curtailable Service Rider 10

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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 51
Canceling P.S.C. Electric No. 9, Original Sheet No. 51

Standard Rate Rider **CSR30**
Curtailable Service Rider 30

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to customers served under applicable power schedules who contract for not less than 1,000 kilowatts individually. The aggregate service under P.S.C. No. 9, CSR10 and CSR30 for Louisville Gas and Electric Company is limited to 100 megawatts in addition to the contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric Company as of August 1, 2010.

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed three hundred and fifty (350) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. A curtailment is a continuous event with a start and stop time that may have both physical curtailments and buy-through options within the interval between the start and stop time. Company may request or cancel a curtailment at any time during any hour of the year, but shall give no less than thirty (30) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year without a buy-through option during system reliability events. For the purposes of this rider, a system reliability event is any condition or occurrence: 1) that impairs KU and LG&E's ability to maintain service to contractually committed system load; 2) where KU and LG&E's ability to meet their compliance obligations with NERC reliability standards cannot otherwise be achieved; or 3) that KU and LG&E reasonably anticipate will last more than six hours and could require KU and LG&E to call upon automatic reserve sharing ("ARS") at some point during the event. Company may also request at its sole discretion up to 250 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements.

Curtailable load and compliance with a request for curtailment shall be measured in one of the following ways:

> Option A -- Customer may contract for a given amount of firm demand, as measured on the demand basis of the standard rate on which Customer is billed. During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price, as applicable, shall apply to the difference in the actual kWh during any requested curtailment and the contracted firm demand multiplied by the time period (hours) of curtailment [Actual

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DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 51

Standard Rate Rider **CSR30**
Curtailable Service Rider 30

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to customers served under applicable power schedules who
contract for not less than 1,000 kVA individually. The aggregate service under CSR10 and T
CSR30 for Louisville Gas and Electric Company is limited to 100 MVA in addition to the T
contracted curtailable load under P.S.C. No. 7, CSR1 for Louisville Gas and Electric Company as of August 1, 2010.

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification
by Company. Requests for curtailment shall not exceed one hundred (100) hours per year nor T
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 T
shall give no less than thirty (30) minutes notice when either requesting or canceling a curtailment.

Company may request at its sole discretion up to 100 hours of physical curtailment per year. T
Curtailable load and compliance with a request for curtailment shall be measured in one of the T
following ways:

> Option A -- Customer may contract for a given amount of firm demand in kVA. T
> During a request for physical curtailment, Customer shall reduce its demand to the firm demand designated in the contract. 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.
>
> Non-compliance for each requested physical curtailment shall be the measured positive value determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) the Customer's maximum demand during such curtailment.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 51.1
Canceling P.S.C. Electric No. 9, Original Sheet No. 51.1

Standard Rate Rider **CSR30**
Curtailable Service Rider 30

kWh – (firm kVA x hours curtailed)]. The measured demand in excess of the firm load during each requested physical curtailment in the billing period shall be the measure of non-compliance, as measured on the demand basis of the standard rate on which Customer is billed.

Option B -- Customer may contract for a given amount of curtailable load by which Customer shall agree to reduce its demand at any time by such Designated Curtailable Load. During a request for physical curtailment, Customer shall reduce its demand to a level equal to the maximum demand (as measured on the demand basis of the standard rate on which Customer is billed) immediately prior to the curtailment less the designated curtailable load. During a request for curtailment with a buy-through option, the Automatic Buy-Through Price shall apply to the difference in the actual kWh during any requested curtailment and the product of Customer's maximum load immediately preceding curtailment less Customer's designated curtailable load designated in the contract multiplied by the time period (hours) of a requested curtailment {Actual kWh – [(Max kVA preceding – Designated Curtailable kVA) x hours of requested curtailment]}. Non-compliance for each requested physical curtailment shall be the measured positive value determined by subtracting (i) Customer's designated curtailable load from (ii) Customer's maximum demand immediately preceding the curtailment and then subtracting such difference from (iii) the Customer's maximum demand during such curtailment.

RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service	$ 4.30 per kVA of Curtailable Billing Demand
Primary Voltage Service	$ 4.40 per kVA of Curtailable Billing Demand
Non-Compliance Charge of:	$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.

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 51.1

Standard Rate Rider **CSR30**
Curtailable Service Rider 30

T

RATE

Customer will receive the following credits for curtailable service during the month:

Transmission Voltage Service	$ 4.30 per kVA of Curtailable Billing Demand
Primary Voltage Service	$ 4.40 per kVA of Curtailable Billing Demand
Non-Compliance Charge of:	$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. T

For a Customer electing Option B, Curtailable Billing Demand shall be the Customer Designated Curtailable Load, as described above.

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DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 51.2
Canceling P.S.C. Electric No. 9, Original Sheet No. 51.2

Standard Rate Rider **CSR30**
Curtailable Service Rider 30

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.

AUTOMATIC BUY-THROUGH PRICE

The Automatic Buy-Through Price per kWh shall be determined daily in accordance with the following formula:

Automatic Buy-Through Price = NGP x .012000 MMBtu/kWh

Where: NGP represents the mid-point price for natural gas ($/MMBtu) posted for the day in *Platts Gas Daily* for Dominion—South Point and will be used for the electrical day from 12 midnight to midnight. Also the posted price for Monday or the day after a holiday is the posted price for Saturday, Sunday and the holiday.

TERM OF CONTRACT

The minimum original contract period shall be one (1) year and thereafter until terminated by giving at least six (6) months previous written notice, but Company may require that contract be executed for a longer initial term when deemed reasonably necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

When the Company requests curtailment, upon request by the Customer, the Company shall provide a good-faith, non-binding estimate of the duration of requested curtailment. In addition, upon request by the Company, the Customer shall provide to the Company a good-faith, non-binding short-term operational schedule for their facility. Upon request by the Customer, the Company will provide, once per month, to the Customer an explanation of the reasons for any request for curtailment.

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 51.2

Standard Rate Rider **CSR30**
Curtailable Service Rider 30

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. T

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply.

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DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Second Revision of Original Sheet No. 55
Canceling P.S.C. Electric No. 9, First Revision of Original Sheet No. 55

Standard Rate Rider SQF
Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE:
In all territory served.

AVAILABILITY OF SERVICE
This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy only from the owner of qualifying cogeneration or small power production facilities of 100 kW or less (such owner being hereafter called "Seller") installed on Seller's property to provide all or part of its requirements of electrical energy, or from which facilities Seller may elect to sell to Company all or part of such output of electrical energy.

Company will permit Seller's generating facilities to operate in parallel with Company's system under conditions set out below under Parallel Operation.

Company will purchase such energy from Seller at the Rate, A or B, set out below and selected as hereafter provided, and under the terms and conditions stated herein. Company reserves the right to change the said Rates, upon proper filing with and acceptance by the jurisdictional Commission.

RATE A: TIME-DIFFERENTIATED RATE

1. For summer billing month of June, July, August and September, during the hours 9:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours),	$0.04041 per kWh.
2. For winter billing months of December, January and February, during the hours 7:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours),	$0.03536 per kWh.
3. During all other hours (off-peak hours)	$0.03327 per kWh.

Determination of On-Peak and Off-Peak Hours: On-peak hours are defined as the hours of 9:01 A.M. through 10:00 P.M., E.D.T. (8:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 1 above), and the hours of 7:01 A.M. through 10:00 P.M., E.D.T. (6:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 2 above). Off-peak hours are defined as all hours other than those listed as on-peak (under 3 above). Company reserves the right to change the hours designated as on-peak from time to time as conditions indicate to be appropriate.

RATE B: NON-TIME-DIFFERENTIATED RATE

For all kWh purchased by Company,	$0.03443 per kWh

DATE OF ISSUE: May 30, 2014

DATE EFFECTIVE: June 30, 2014

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 55

Standard Rate Rider SQF
Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE:
In all territory served.

AVAILABILITY OF SERVICE
This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy only from the owner of qualifying cogeneration or small power production facilities of 100 kW or less (such owner being hereafter called "Seller") installed on Seller's property to provide all or part of its requirements of electrical energy, or from which facilities Seller may elect to sell to Company all or part of such output of electrical energy.

Company will permit Seller's generating facilities to operate in parallel with Company's system under conditions set out below under Parallel Operation.

Company will purchase such energy from Seller at the Rate, A or B, set out below and selected as hereafter provided, and under the terms and conditions stated herein. Company reserves the right to change the said Rates, upon proper filing with and acceptance by the jurisdictional Commission.

RATE A: TIME-DIFFERENTIATED RATE

1. For summer billing month of June, July, August and September, during the hours 9:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours),	$0.04041 per kWh.
2. For winter billing months of December, January and February, during the hours 7:01 A.M. thru 10:00 P.M. weekdays exclusive of holidays (on-peak hours),	$0.03536 per kWh.
3. During all other hours (off-peak hours)	$0.03327 per kWh.

Determination of On-Peak and Off-Peak Hours: On-peak hours are defined as the hours of 9:01 A.M. through 10:00 P.M., E.D.T. (8:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 1 above), and the hours of 7:01 A.M. through 10:00 P.M., E.D.T. (6:01 A.M. through 9:00 P.M., E.S.T.), Mondays through Fridays exclusive of holidays (under 2 above). Off-peak hours are defined as all hours other than those listed as on-peak (under 3 above). Company reserves the right to change the hours designated as on-peak from time to time as conditions indicate to be appropriate.

RATE B: NON-TIME-DIFFERENTIATED RATE

For all kWh purchased by Company,	$0.03443 per kWh

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: June 30, 2014

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
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Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 55.2
Canceling P.S.C. Electric No. 9, 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,

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DATE EFFECTIVE: April 17, 1999

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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: November 26, 2014

DATE EFFECTIVE: April 17, 1999

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 55.3
Canceling P.S.C. Electric No. 9, 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: January 31, 2013

DATE EFFECTIVE: April 17, 1999

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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: November 26, 2014

DATE EFFECTIVE: April 17, 1999

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 56

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

AVAILABILITY

In all territory served.

APPLICABILITY OF SERVICE

Applicable to any small power production or cogeneration "qualifying facility" with capacity over 100 kW as defined by the Kentucky Public Service Commission Regulation 807 KAR 5:054, and which contracts to sell energy or capacity or both to Company.

RATES FOR PURCHASES FROM QUALIFYING FACILITIES

Energy Component Payments

The hourly avoided energy cost (AEC) in $ per MWh, which is payable to a QF for delivery of energy, shall be equal to Company's actual variable fuel expenses, for Company-owned coal and natural gas-fired production facilities, divided by the associated megawatt-hours of generation, as determined for the previous month. The total amount of the avoided energy cost payment to be made to a QF in an hour is equal to [AEC x E_{QF}], where E_{QF} is the amount of megawatt-hours delivered by a QF in that hour and which are determined by suitable metering.

Capacity Component Payments

The hourly avoided capacity cost (ACC) in $ per MWh, which is payable to a QF for delivery of capacity, shall be equal to the effective purchase price for power available to Company from the inter-utility market (which includes both energy and capacity charges) less Company's actual variable fuel expense (AEC). The total amount of the avoided capacity cost payment to be made to a QF in an hour is equal to [ACC x CAP_i], where CAP_i, the capacity delivered by the QF, is determined on the basis of the system demand (D_i) and Company's need for capacity in that hour to adequately serve the load.

Determination of CAP_i

For the following determination of CAP_i, $C_{LG\&E}$ represents Company's installed or previously arranged capacity at the time a QF signs a contract to deliver capacity; C_{QF} represents the actual capacity provided by a QF, but no more than the contracted capacity; and C_M represents capacity purchased from the inter-utility market.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: November 1, 1995

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 56

Standard Rate Rider LQF

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: November 1, 1995

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 56.1

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

1. System demand is less than or equal to Company's capacity:
   $D_1 \leq C_{LG\&E}$; $CAP_i = 0$

2. System demand is greater than Company's capacity but less than or equal to the total of Company's capacity and the capacity provided by a QF:

   $C_{LG\&E} < D_i \leq [C_{LG\&E} + C_{QF}]$; $CAP_i = C_M$

3. System demand is greater than the total of Company's capacity and the capacity provided by a QF:

   $D_i > [C_{LG\&E} + C_{QF}]$; $CAP_i = C_{QF}$

PAYMENT

Company shall pay each bill for electric power rendered to it in accordance with the terms of the contract, within 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: January 31, 2013

DATE EFFECTIVE: November 1, 1995

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 56.1

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: November 1, 1995

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 57
Canceling P.S.C. Electric No. 9, Original Sheet No. 57

Standard Rate Rider **NMS**
Net Metering Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to any customer-generator who owns and operates a generating facility located on Customer's premises that generates electricity using solar, wind, biomass or biogas, or hydro energy in parallel with Company's electric distribution system to provide all or part of Customer's electrical requirements, and who executes Company's written Application for Interconnection and Net Metering. The generation facility shall be limited to a maximum rated capacity of 30 kilowatts. This Standard Rate Rider is intended to comply with all provisions of the Interconnection and Net Metering Guidelines approved by the Public Service Commission of Kentucky, which can be found on-line at www.psc.ky.gov as Appendix A to the January 8, 2009 Order in Administrative Case No. 2008-00169.

METERING AND BILLING

Net metering service shall be measured using a single meter or, as determined by Company, additional meters and shall be measured in accordance with standard metering practices by metering equipment capable of registering power flow in both directions for each time period defined by the applicable rate schedule. This net metering equipment shall be provided without any cost to the Customer. This provision does not relieve Customer's responsibility to pay metering costs embedded in the Company's Commission-approved base rates. Additional meters, requested by Customer, will be provided at Customer's expense.

If electricity generated by Customer and fed back to Company's system exceeds the electricity supplied to Customer from the system during a billing period, Customer shall receive a credit for the net delivery on Customer's bill for the succeeding billing periods. Any such unused excess credits will be carried forward and drawn on by Customer as needed. Unused excess credits existing at the time Customer's service is terminated end with Customer's account and are not transferrable between customers or locations.

NET METERING SERVICE INTERCONNECTION GUIDELINES

General – Customer shall operate the generating facility in parallel with Company's system under the following conditions and any other conditions required by Company where unusual circumstances arise not covered herein:

1. Customer to own, operate, and maintain all generating facilities on their premises. Such facilities shall include, but not be limited to, necessary control equipment to synchronize frequency, voltage, etc., between Customer's and Company's system as well as adequate protective equipment between the two systems. Customer's voltage at the point of interconnection will be the same as Company's system voltage.
2. Customer will be responsible for operating all generating facilities owned by Customer, except as specified hereinafter. Customer will maintain its system in synchronization with Company's system.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 17, 2009

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 T

"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. T If Customer takes service under 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 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.

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of original Sheet No. 57.1
Canceling P.S.C. Electric No. 9, Original Sheet No. 57.1

Standard Rate Rider **NMS**
Net Metering Service

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

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.
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.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: November 1, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010 and
2010-00204 dated September 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 57.1

Standard Rate Rider **NMS**
Net Metering Service

NET METERING SERVICE INTERCONNECTION GUIDELINES T

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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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate Rider **NMS**
Net Metering Service

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

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 to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, the Company will notify Customer, and the time between notification and submission of the information shall not be counted towards the 30 business days. Approval is contingent upon an initial inspection and witness test at the discretion of Company.

Customer submitting a "Level 2 - Application for Interconnection and Net Metering" will provide a non-refundable inspection and processing fee of $100, and in the event that the Company determines an impact study to be necessary, shall be responsible for any reasonable costs of up to $1,000 of documented costs for the initial impact study.

Additional studies requested by Customer shall be at Customer's expense.

CONDITIONS OF INTERCONNECTION

Customer may operate his net metering generator in parallel with Company's system when complying with the following conditions:

1. Customer shall install, operate, and maintain, at Customer's sole cost and expense, any control, protective, or other equipment on Customer's system required by Company's technical interconnection requirements based on IEEE 1547, NEC, accredited testing laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the net metering generating facility in parallel with Company's system. Customer bears full responsibility for the installation, maintenance and safe operation of the net metering generating facility. Upon reasonable request from Company, Customer shall demonstrate compliance.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: April 17, 1999

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Standard Rate Rider **NMS**
Net Metering Service

NET METERING SERVICE INTERCONNECTION GUIDELINES (continued)

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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 to whether the request is approved or, if denied, the reason(s) for denial. If additional information is required, the Company will notify Customer, and the time between notification and submission of the information shall not be counted towards the 30 business days. Approval is contingent upon an initial inspection and witness test at the discretion of Company.

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 57.3
Canceling P.S.C. Electric No. 9, Original Sheet No. 57.3

Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

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.
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

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ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 57.3

Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION T

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. T

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 57.4
Canceling P.S.C. Electric No. 9, Original Sheet No. 57.4

Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

properly and legibly identified for so long as the net metering generator is operational. The disconnect switch shall be accessible to Company personnel at all times. Company may waive the requirement for an external disconnect switch for a net metering generator at its sole discretion, and on a case by case basis.

8. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the Customer to discontinue operation of the net metering generator if Company believes that:
   a) continued interconnection and parallel operation of the net metering generator with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or Customer's electric system;
   b) the net metering generator is not in compliance with the requirements of this rate schedule, and the non-compliance adversely affects the safety, reliability or power quality of Company's electric system; or
   c) the net metering generator interferes with the operation of Company's electric system.

   In non-emergency situations, Company shall give Customer notice of noncompliance including a description of the specific noncompliance condition and allow Customer a reasonable time to cure the noncompliance prior to isolating the Generating Facilities. In emergency situations, where the Company is unable to immediately isolate or cause Customer to isolate only the net metering generator, Company may isolate Customer's entire facility.
9. Customer agrees that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in net metering generator capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in net metering generator capacity is allowed without approval.
10. Customer shall protect, indemnify and hold harmless Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by Customer or Customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating

    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.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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. 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 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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 57.5
Canceling P.S.C. Electric No. 9, Original Sheet No. 57.5

Standard Rate Rider **NMS**
Net Metering Service

CONDITIONS OF INTERCONNECTION (continued)

11. Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial or other policy) for generating facilities. Customer shall upon request provide Company with proof of such insurance at the time that application is made for net metering.

12. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

13. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify Customer in writing and list what must be done to place the facility in compliance.

14. Customer shall retain any and all Renewable Energy Credits (RECs) generated by Customer's generating facilities.

DEFINITIONS

"Billing period" shall be the time period between the dates on which Company issues the customer's bills.

"Billing Period Credit" shall be the electricity generated by the customer that flows into the electric system and which exceeds the electricity supplied to the customer from the electric system during any billing period.

TERMS AND CONDITIONS

Except as provided herein, service will be furnished under Company's Terms and Conditions applicable hereto.

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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. T

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.

T

TERMS AND CONDITIONS

Except as provided herein, service will be furnished under Company's Terms and Conditions applicable hereto.

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DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 57.6
Canceling P.S.C. Electric No. 9, 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:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ____________________ Account Number: ____________

Customer Address: ____

Customer Phone No.: ____________ Customer E-mail Address: ____________________

Project Contact Person: ____

Phone No.**:** ____________ E-mail Address (Optional): ____________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

Energy Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Inverter Manufacturer and Model #: ________________________________

Inverter Power Rating: ____________ Inverter Voltage Rating: ____________

Power Rating of Energy Source (i.e., solar panels, wind turbine): ____________________

Is Battery Storage Used: ____No _____Yes If Yes, Battery Power Rating: ____________________

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing location of Utility's meter, energy source, ***(optional: Utility accessible disconnect switch)*** and inverter.

Attach single line drawing showing all electrical equipment from the Utility's metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ____________________

DATE OF ISSUE: January 31, 2013

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ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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2010-00204 dated September 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ____________________ Account Number: ____________

Customer Address: ____

Customer Phone No.: ____________ Customer E-mail Address: ____________________

Project Contact Person: ____

Phone No.**:** ____________ E-mail Address (Optional): ____________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

Energy Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Inverter Manufacturer and Model #: ________________________________

Inverter Power Rating: ____________ Inverter Voltage Rating: ____________

Power Rating of Energy Source (i.e., solar panels, wind turbine): ____________________

Is Battery Storage Used: ____No _____Yes If Yes, Battery Power Rating: ____________________

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing location of Utility's meter, energy source, ***(optional: Utility accessible disconnect switch)*** and inverter.

Attach single line drawing showing all electrical equipment from the Utility's metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ____________________

DATE OF ISSUE: November 26, 2014

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Standard Rate Rider **NMS**
Net Metering Service

LEVEL 2

Application for Interconnection and Net Metering

*Use this application form when a generating facility is not inverter-based or is not certified by a nationally recognized testing laboratory to meet the requirements of **UL** 1741 or does not meet any of the additional conditions under Level 1.*

Submit this Application, along with an application fee of $100, to:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ______________________ Account Number: ______________

Customer Address: ____

Project Contact Person: ____

Phone No.: ______________ E-mail Address (Optional): ____________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

Total Generating Capacity of Generating Facility: _______________________

Type of Generator: ____Inverter-Based ____Synchronous ____Induction

Power Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Adequate documentation and information must be submitted with this application to be considered complete. Typically this should include the following:

1. Single-line diagram of the customer's system showing all electrical equipment from the generator to the point *of* interconnection with the Utility's distribution system, including generators, transformers, switchgear, switches, breakers, fuses, voltage transformers, current transformers, wire sizes, equipment ratings, and transformer connections.
2. Control drawings for relays and breakers.
3. Site Plans showing the physical location of major equipment.
4. Relevant ratings of equipment. Transformer information should include capacity ratings, voltage ratings, winding arrangements, and impedance.
5. If protective relays are used, settings applicable to the interconnection protection. If programmable relays are used, a description of how the relay is programmed to operate as applicable to interconnection protection.
6. A description of how the generator system will be operated including all modes of operation.
7. For inverters, the manufacturer name, model number, and AC power rating. For certified inverters, attach documentation showing that inverter is certified by *a* nationally recognized testing laboratory to meet the requirements of UL 1741.
8. For synchronous generators, manufacturer and model number, nameplate ratings, and impedance data (Xd, Xd, & Xd).
9. For induction generators, manufacturer and model number, nameplate ratings, and locked rotor current.

Customer Signature: ______________________________ Date: ______________

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
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2009-00549 dated July 30, 2010 and
2010-00204 dated September 30, 2010**

Standard Rate Rider **NMS**
Net Metering Service

LEVEL 2

Application for Interconnection and Net Metering

*Use this application form when a generating facility is not inverter-based or is not certified by a nationally recognized testing laboratory to meet the requirements of **UL** 1741 or does not meet any of the additional conditions under Level 1.*

Submit this Application, along with an application fee of $100, to:

Louisville Gas and Electric Company, Attn: Customer Commitment,
P. O. Box 32010, Louisville, KY 40232

If you have questions regarding this Application or its status, contact LG&E at:

502-627-2202 or customer.commitment@lge-ku.com

Customer Name: ______________________ Account Number: ______________

Customer Address: ____

Project Contact Person: ____

Phone No.: ______________ E-mail Address (Optional): ____________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

____

Total Generating Capacity of Generating Facility: _______________________

Type of Generator: ____Inverter-Based ____Synchronous ____Induction

Power Source: ____Solar ____Wind ____Hydro ____Biogas ____Biomass

Adequate documentation and information must be submitted with this application to be considered complete. Typically this should include the following:

1. Single-line diagram of the customer's system showing all electrical equipment from the generator to the point *of* interconnection with the Utility's distribution system, including generators, transformers, switchgear, switches, breakers, fuses, voltage transformers, current transformers, wire sizes, equipment ratings, and transformer connections.
2. Control drawings for relays and breakers.
3. Site Plans showing the physical location of major equipment.
4. Relevant ratings of equipment. Transformer information should include capacity ratings, voltage ratings, winding arrangements, and impedance.
5. If protective relays are used, settings applicable to the interconnection protection. If programmable relays are used, a description of how the relay is programmed to operate as applicable to interconnection protection.
6. A description of how the generator system will be operated including all modes of operation.
7. For inverters, the manufacturer name, model number, and AC power rating. For certified inverters, attach documentation showing that inverter is certified by *a* nationally recognized testing laboratory to meet the requirements of UL 1741.
8. For synchronous generators, manufacturer and model number, nameplate ratings, and impedance data (Xd, Xd, & Xd).
9. For induction generators, manufacturer and model number, nameplate ratings, and locked rotor current.

Customer Signature: ______________________________ Date: ______________

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: November 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
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2009-00549 dated July 30, 2010 and
2010-00204 dated September 30, 2010**

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 60
Canceling P.S.C. Electric No. 9, Original Sheet No. 60

Standard Rate Rider **EF**

Excess Facilities

APPLICABILITY

In all territory served.

AVAILABILITY OF SERVICE

This rider is available for non-standard service facilities which are considered to be in excess of 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	1.32%

(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	0.54%

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 60

Standard Rate Rider **EF**

Excess Facilities

APPLICABILITY

In all territory served.

AVAILABILITY OF SERVICE

This rider is available for non-standard service facilities which are considered to be in excess of 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

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Percentage With No Contribution-in-Aid-of-Construction	1.32%

(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	0.54%

DATE OF ISSUE: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

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.

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DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2012-00222 dated December 20, 2012

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.

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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.

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 61

Standard Rate Rider **RC**

Redundant Capacity

APPLICABLE

This rate is applicable to customers served under Company's rate schedules which include a demand charge or a special contract including a demand charge.

AVAILABILITY

Available to customers requesting the reservation of capacity on Company's facilities which are shared by other customers when Company has, and is willing, to reserve such capacity. Such facilities represent a redundant delivery to provide electric service to Customer's facility in the event that an emergency or unusual occurrence renders Customer's principal delivery unavailable for providing service. Where Customer desires to split a load between multiple meters on multiple feeds and contract for Redundant Capacity on those feeds, service is contingent on the practicality of metering to measure any transferred load to the redundant feed.

RATE:

<u>Capacity Reservation Charge</u>

Secondary Distribution	$1.17 per kW/kVA per Month
Primary Distribution	$0.83 per kW/kVA per Month

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 (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.

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DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 61

Standard Rate Rider **RC**

Redundant Capacity

APPLICABLE

This rate is applicable to customers served under Company's rate schedules which include a demand charge or a special contract including a demand charge.

AVAILABILITY

Available to customers requesting the reservation of capacity on Company's facilities which are shared by other customers when Company has, and is willing, to reserve such capacity. Such facilities represent a redundant delivery to provide electric service to Customer's facility in the event that an emergency or unusual occurrence renders Customer's principal delivery unavailable for providing service. Where Customer desires to split a load between multiple meters on multiple feeds and contract for Redundant Capacity on those feeds, service is contingent on the practicality of metering to measure any transferred load to the redundant feed.

RATE:

<u>Capacity Reservation Charge</u>

Secondary Distribution	$1.43 per kW/kVA per Month	I
Primary Distribution	$1.26 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 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 (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.

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 62
Canceling P.S.C. Electric No. 9, Original Sheet No. 62

Standard Rate Rider **SS**
Supplemental or Standby Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This service is available as a rider to customers whose premises or equipment are regularly supplied with electric energy from generating facilities other than those of Company and who desire to contract with Company for reserve, breakdown, supplemental or standby service.

Where a customer-generator supplies all or part of the customer-generator's own load and desires Company to provide supplemental or standby service for that load, the customer-generator must contract for such service under Company's Supplemental or Standby Service Rider, otherwise Company has no obligation to supply the non-firm service. This requirement does not apply to Net Metering Service (Rider NMS).

RATE

	Secondary	Primary	Transmission
Contract Demand per kW/kVA per Month:	$12.86	$12.23	$11.04

CONTRACT DEMAND

Contract Demand is defined as the number of kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) mutually agreed upon as representing Customer's maximum service requirements and contracted for by Customer; provided, however, if such number of kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) is exceeded by a recorded demand, such recorded demand shall become the new contract demand commencing with the month in which recorded and continuing for the remaining term of the contract or until superseded by a higher recorded demand.

MINIMUM CHARGE

Electric service actually used each month will be charged for in accordance with the provisions of the applicable rate schedule; provided, however, the minimum billing under that rate schedule shall in no case be less than an amount calculated at the appropriate rate above applied to the Contract Demand.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 62

Standard Rate Rider **SS**
Supplemental or Standby Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This service is available as a rider to customers whose premises or equipment are regularly supplied with electric energy from generating facilities other than those of Company and who desire to contract with Company for reserve, breakdown, supplemental or standby service.

Where a customer-generator supplies all or part of the customer-generator's own load and desires Company to provide supplemental or standby service for that load, the customer-generator must contract for such service under Company's Supplemental or Standby Service Rider, otherwise Company has no obligation to supply the non-firm service. This requirement does not apply to Net Metering Service (Rider NMS).

RATE

	Secondary	Primary	Transmission	
Contract Demand per kW/kVA per Month:	$13.57	$12.30	$10.83	I/I/R

CONTRACT DEMAND

Contract Demand is defined as the number of kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) mutually agreed upon as representing Customer's maximum service requirements and contracted for by Customer; provided, however, if such number of kW/kVA (as is appropriate for the demand basis of the standard rate on which Customer is billed) is exceeded by a recorded demand, such recorded demand shall become the new contract demand commencing with the month in which recorded and continuing for the remaining term of the contract or until superseded by a higher recorded demand.

MINIMUM CHARGE

Company will bill Customer monthly for all of the charges under Customer's applicable rate schedule, including, but not limited to, the applicable basic service charge, energy charges, and adjustment clauses. In addition to those charges, Company will bill Customer monthly a demand charge that is the greater of: (1) the Customer's total demand charge calculated under the applicable rate schedule; or (2) the demand charge calculated using the applicable demand rate shown above applied to the Contract Demand. If Customer's applicable rate schedule does not contain a demand charge, the Customer's monthly demand charge will be the demand charge calculated using the applicable demand rate shown above applied to the Contract Demand. T

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 62.1
Canceling P.S.C. Electric No. 9, Original Sheet No. 62.1

Standard Rate Rider **SS**
Supplemental or Standby Service

SPECIAL TERMS AND CONDITIONS

1) In order to protect its equipment from overload damage, Company may require customer to install at Customer's own expense an approved shunt trip type breaker and an approved automatic pole-mounted disconnect. Such circuit breakers shall be under the sole control of Company and will be set by Company to break the connection with its service in the event Customer's demand materially exceeds that for which Customer contracted.

2) In the event Customer's use of service is intermittent or subject to violent fluctuations, Company will require Customer to install and maintain at Customer's own expense suitable equipment to satisfactorily limit such intermittence or fluctuations.

3) Customer's generating equipment shall not be operated in parallel with Company's service until the manner of such operation has been approved by Company and is in compliance with Company's operating standards for system reliability and safety.

TERM OF CONTRACT

The minimum contract period shall be one (1) year, but Company may require that a contract be executed for a longer initial term when deemed necessary by the size of load or special conditions.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions except as provided herein.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 62.1

Standard Rate Rider **SS**
Supplemental or Standby Service

DUE DATE OF BILL T

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) T
calendar days) from the date of the bill. T

SPECIAL TERMS AND CONDITIONS

1) In order to protect its equipment from overload damage, Company may require customer to install at Customer's own expense an approved shunt trip type breaker and an approved automatic pole-mounted disconnect. Such circuit breakers shall be under the sole control of Company and will be set by Company to break the connection with its service in the event Customer's demand materially exceeds that for which Customer contracted.

2) In the event Customer's use of service is intermittent or subject to violent fluctuations, Company will require Customer to install and maintain at Customer's own expense suitable equipment to satisfactorily limit such intermittence or fluctuations.

3) Customer's generating equipment shall not be operated in parallel with Company's service until the manner of such operation has been approved by Company and is in compliance with Company's operating standards for system reliability and safety.

TERM OF CONTRACT

The minimum contract period shall be one (1) year, but Company may require that a contract be executed for a longer initial term when deemed necessary by the size of load or special conditions.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions except as provided herein.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 65
Canceling P.S.C. Electric No. 9, Original Sheet No. 65

Standard Rate Rider **IL**

Rider for Intermittent Loads

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule applies to all loads having a detrimental effect upon the electric service rendered to other customers of Company or upon Company's facilities.

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company, in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other desirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 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.

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 65

Standard Rate Rider **IL**

Rider for Intermittent Loads

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule applies to all loads having a detrimental effect upon the electric service rendered to other customers of Company or upon Company's facilities.

Where Customer's use of service is intermittent, subject to violent or extraordinary fluctuations, or produces unacceptable levels of harmonic current, in each case as determined by Company, in its reasonable discretion, Company reserves the right to require Customer to furnish, at Customer's own expense, suitable equipment (as approved by Company in its reasonable discretion) to meter and limit such intermittence, fluctuation, or harmonics to the extent reasonably requested by Company. Without limiting the foregoing, Company may require such equipment if, at any time, the megavars, harmonics, and other desirable electrical characteristics produced by the Customer exceed the limits set forth in the IEEE standards for such characteristics. In addition, if the Customer's use of Company's service under this schedule causes such undesirable electrical characteristics in an amount exceeding those IEEE standards, such use shall be deemed to cause a dangerous condition which could subject any person to imminent harm or result in substantial damage to the property of Company or others, and Company shall therefore terminate service to the Customer in accordance with 807 KAR 5:006, Section 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: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 65.1

Standard Rate Rider **IL**

Rider for 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: January 31, 2013

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ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 65.1

Standard Rate Rider **IL**

Rider for 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: November 26, 2014

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 66

Standard Rate Rider TS

Temporary and/or Seasonal Electric Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider is available at the option of the Customer where Customer's business does not require permanent installation of Company's facilities and is of such nature to require:

1. only seasonal service or temporary service, including service provided for construction of residences or commercial buildings, and where in the judgment of Company the local and system electrical facility capacities are adequate to serve the load without impairment of service to other customers; or
2. where Customer has need for temporary use of Company facilities and Company has facilities it is willing to provide.

This service is available for not less than one (1) month (approximately 30 days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes.

CONDITIONS

Company may permit such electric loads to be served on the rate schedule normally applicable, but without requiring a yearly contract and minimum, substituting therefore the following conditions and agreements:

1. Customer shall pay Company for all costs of making temporary connections, including cost of installing necessary transformers, meters, poles, wire and any other material, and any cost of material which cannot be salvaged, and the cost of removing such facilities when load has ceased.

2. Customer shall pay regular rate of the applicable electric rate schedule.

3. Where Customer is receiving service under a standard rate and has need for temporary use of Company facilities, Customer will pay for non-salvageable materials outlined in (1) above plus a monthly charge for the salvageable equipment at the Percentage With No Contribution -in-Aid-of-Construction specified on the Excess Facilities Rider, Rate Sheet No. 60.

DATE OF ISSUE: January 31, 2013

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 66

Standard Rate Rider TS

Temporary and/or Seasonal Electric Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider is available at the option of the Company where: T

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. where Customer has need for temporary intermittent use of Company facilities and Company T
   has facilities it is willing to provide Customer for installation and operational testing of T
   Customer's equipment. T

This service is available for not less than one (1) month (approximately 30 days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing
purposes. Where this service is provided under 2 or 3, above, the Company will determine the T
term of service, which shall not exceed one (1) year. 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:

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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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 67

Standard Rate Rider

Kilowatt-Hours Consumed By Lighting Units

APPLICABLE

Determination of energy set out below applies to the Company's non-metered lighting rate schedules.

DETERMINATION OF ENERGY CONSUMPTION

The applicable fuel clause charge or credit will be based on the kilowatt-hours calculated by multiplying the kilowatt load of each light times the number of hours that light is in use during the billing month. The kilowatt load of each light is shown in the section titled RATE. The number of hours a light will be in use during a given month is from dusk to dawn as shown in the following Hours Use Table.

HOURS USE TABLE

Month	Hours Light Is In Use
JAN	407
FEB	344
MAR	347
APR	301
MAY	281
JUN	257
JUL	273
AUG	299
SEP	322
OCT	368
NOV	386
DEC	415
TOTAL FOR YEAR	4,000 HRS.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 70

Standard Rate Rider **SGE**

Small Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard RS or GS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.

b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one MWh of green power.

RATE

Voluntary monthly contributions of any amount in $5.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $5.00 increments (e.g., $5.00, $10.00, $15.00, or more per month) An eligible Customer may participate in Company's "Green Energy Program" by making a request to Company's Call Center or through Company's website enrollment form and may withdraw at any time through a request to Company's Call Center. Funds provided by Customer to Company are not refundable.

b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.

c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

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DATE EFFECTIVE: June 1, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2009-00467 dated February 22, 2010**

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 70

Standard Rate Rider **SGE**

Small Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard RS or GS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates.

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.

b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one MWh of green power.

RATE

Voluntary monthly contributions of any amount in $5.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $5.00 increments (e.g., $5.00, $10.00, $15.00, or more per month) An eligible Customer may participate in Company's "Green Energy Program" by making a request to Company's Call Center or through Company's website enrollment form and may withdraw at any time through a request to Company's Call Center. Funds provided by Customer to Company are not refundable.

b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.

c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: June 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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2009-00467 dated February 22, 2010**

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 70.1

Standard Rate Rider **LGE**
Large Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard PS, TODS, ITODP, CTODP, 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 MWh of green power.

RATE

Voluntary monthly contributions of any amount in $13.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $13.00 increments (e.g., $13.00, $26.00, $39.00, or more per month). An eligible customer may participate in Company's "Green Energy Program" by making a request to the Company and may withdraw at any time through a request to the Company. Funds provided by Customer to Company are not refundable.
b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.
c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 70.1

Standard Rate Rider **LGE**
Large Green Energy Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Service under this rider is available to customers receiving service under Company's standard PS, TODS, TODP, RTS, or FLS rate schedules as an option to participate in Company's "Green Energy Program" whereby Company will aggregate the resources provided by the participating customers to develop green power, purchase green power, or purchase Renewable Energy Certificates. T

DEFINITIONS

a) Green power is that electricity generated from renewable sources including but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified.
b) A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental-benefits attributes of one MWh of green power.

RATE

Voluntary monthly contributions of any amount in $13.00 increments

TERMS AND CONDITIONS

a) Customers may contribute monthly as much as they like in $13.00 increments (e.g., $13.00, $26.00, $39.00, or more per month). An eligible customer may participate in Company's "Green Energy Program" by making a request to the Company and may withdraw at any time through a request to the Company. Funds provided by Customer to Company are not refundable.
b) Customers may not owe any arrearage prior to entering the "Green Energy Program". Any customer failing to pay the amount the customer pledged to contribute may be removed from the "Green Energy Program." Any customer removed from or withdrawing from the "Green Energy Program" will not be allowed to re-apply for one year.
c) Customer will be billed monthly for the amount Customer has pledged to contribute to the "Green Energy Program." Such billing will be added to Customer's billing under any standard rate schedules plus applicable riders plus applicable adjustment clauses.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 71
Canceling P.S.C. Electric No. 9, Original Sheet No. 71

Standard Rate Rider **EDR**
Economic Development Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available as a rider to customers to be served or being served under Company's Standard Rate Schedules TODS, ITODP, CTODP, and RTS to encourage Brownfield Development or Economic Development (as defined herein). Service under EDR is conditional on approval of a special contract for such service filed with and approved by the Public Service Commission of Kentucky.

RATE

A customer taking service under EDR shall be served according to all of the rates, terms, and conditions of the normally applicable rate schedule subject to the following:

a) for the twelve consecutive monthly billings of the first contract year, the Total Demand Charge shall be reduced by 50%;
b) for the twelve consecutive monthly billings of the second contract year, the Total Demand Charge shall be reduced by 40%;
c) for the twelve consecutive monthly billings of the third contract year, the Total Demand Charge shall be reduced by 30%;
d) for the twelve consecutive monthly billings of the fourth contract year, the Total Demand Charge shall be reduced by 20%;
e) for the twelve consecutive monthly billings of the fifth contract year, the Total Demand Charge shall be reduced by 10%; and
f) all subsequent billing shall be at the full charges stated in the applicable rate schedule.

"Total Demand Charge" is the sum of all demand charges, including any credits provided under any other demand applicable rider, before the EDR discounts described above are applied.

TERMS AND CONDITIONS

<u>Brownfield Development</u>

a) Service under EDR for Brownfield Development is available to customers locating at sites that have been submitted to, approved by, and added to the Brownfield Inventory maintained by the Kentucky Energy and Environment Cabinet (or by any successor entity created and authorized by the Commonwealth of Kentucky).
b) EDR for Brownfield Development is available only to billing loads of 500 kVA (or kW as is appropriate) or greater where the customer takes service from existing Company facilities.

<u>Economic Development</u>

c) Service under EDR for Economic Development is available to:
    1) new customers contracting for a minimum annual average of monthly billing load of 1,000 kVA (or kW as is appropriate); and

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 71

Standard Rate Rider **EDR**
Economic Development Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available as a rider to customers to be served or being served under Company's Standard Rate Schedules TODS, TODP, and RTS to encourage Brownfield Development or Economic Development (as defined herein). Service under EDR is conditional on approval of a special contract for such service filed with and approved by the Public Service Commission of Kentucky. T

RATE

A customer taking service under EDR shall be served according to all of the rates, terms, and conditions of the normally applicable rate schedule subject to the following:

a) for the twelve consecutive monthly billings of the first contract year, the Total Demand Charge shall be reduced by 50%;
b) for the twelve consecutive monthly billings of the second contract year, the Total Demand Charge shall be reduced by 40%;
c) for the twelve consecutive monthly billings of the third contract year, the Total Demand Charge shall be reduced by 30%;
d) for the twelve consecutive monthly billings of the fourth contract year, the Total Demand Charge shall be reduced by 20%;
e) for the twelve consecutive monthly billings of the fifth contract year, the Total Demand Charge shall be reduced by 10%; and
f) all subsequent billing shall be at the full charges stated in the applicable rate schedule.

"Total Demand Charge" is the sum of all demand charges, including any credits provided under any other demand applicable rider, before the EDR discounts described above are applied.

TERMS AND CONDITIONS

<u>Brownfield Development</u>

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 kW as is appropriate) or greater where the customer takes service from existing Company facilities. T

<u>Economic Development</u>

c) Service under EDR for Economic Development is available to:
    1) new customers contracting for a minimum monthly billing load of 1,000 kVA (or kW as is appropriate); and

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 71.1
Canceling P.S.C. Electric No. 9, Original Sheet No. 71.1

Standard Rate Rider **EDR**
Economic Development Rider

TERMS AND CONDITIONS

Economic Development

2) existing customers contracting for a minimum annual average of monthly billing load of 1,000 kVA (or kW as is appropriate) above their Existing Base Load, to be determined as follows:
    i. Company and the existing customer will determine Customer's Existing Base Load by averaging Customer's previous three years' monthly billing loads, subject to any mutually agreed upon adjustments thereto.
    ii. Company and the existing customer must agree upon the Existing Base Load, which shall be an explicit term of the special contract submitted to the Commission for approval before the customer can take service under EDR. Once the Existing Base Load's value is thus established, it will not be subject to variation or eligible for service under EDR.
    iii. This provision is not intended to reduce or diminish in any way EDR service already being provided to all or a portion of a customer's Existing Base Load. Such EDR service would continue under the terms of the contract already existing between the Company and the customer concerning the affected portion of the customer's Existing Base Load.

d) A customer desiring service under EDR for Economic Development must submit an application for service that includes:
    1) a description of the new load to be served;
    2) the number of new employees, if any, Customer anticipates employing associated with the new load;
    3) the capital investment Customer anticipates making associated with the EDR load;
    4) a certification that Customer has been qualified by the Commonwealth of Kentucky for benefits under the Kentucky Business Investment Program.

e) Should Company determine a refundable contribution for the capital investment in Customer-specific facilities required by Company to serve the EDR load would ordinarily be required as set out under Company's Line Extension Plan, I. Special Cases, that amount shall be determined over a fifteen (15) year period and payable at the end of the fifteen (15) year period.

General

f) Company may offer EDR to qualifying new load only when Company has generating capacity available and the new load will not accelerate Company's plans for additional generating capacity over the life of the EDR contract.

g) Customer may request an EDR effective initial billing date that is no later than twelve (12) months after the date on which Company initiates service to Customer.

h) Neither the demand charge reduction nor any unjustified capital investment in facilities will be borne by Company's other customers during the term of the EDR contract.

i) Company may offer differing terms, as appropriate, under special contract to which this rider is a part depending on the circumstances associated with providing service to a particular customer and subject to approval by the Public Service Commission of Kentucky.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 11, 2011

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2011-00103 dated August 11, 2011

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 71.1

Standard Rate Rider **EDR**
Economic Development Rider

TERMS AND CONDITIONS

Economic Development

2) existing customers contracting for a minimum monthly billing load of 1,000 kVA (or kW as is appropriate) above their Existing Base Load, to be determined as follows:
    i. Company and the existing customer will determine Customer's Existing Base Load by averaging Customer's previous three years' monthly billing loads, subject to any mutually agreed upon adjustments thereto.
    ii. Company and the existing customer must agree upon the Existing Base Load, which shall be an explicit term of the special contract submitted to the Commission for approval before the customer can take service under EDR. Once the Existing Base Load's value is thus established, it will not be subject to variation or eligible for service under EDR.
    iii. This provision is not intended to reduce or diminish in any way EDR service already being provided to all or a portion of a customer's Existing Base Load. Such EDR service would continue under the terms of the contract already existing between the Company and the customer concerning the affected portion of the customer's Existing Base Load.

d) A customer desiring service under EDR for Economic Development must submit an application for service that includes:
    1) a description of the new load to be served;
    2) the number of new employees, if any, Customer anticipates employing associated with the new load;
    3) the capital investment Customer anticipates making associated with the EDR load;
    4) a certification that Customer has been qualified by the Commonwealth of Kentucky
    for benefits under the Kentucky Business Investment Program (KBI), or the T
    Kentucky Industrial Revitalization Act (KIRA), or the Kentucky Jobs Retention Act T
    (KJRA), or other comparable programs approved by the Commonwealth of T
    Kentucky. T

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.

T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 71.2

Standard Rate Rider **EDR**
Economic Development Rider

TERM OF CONTRACT

Service will be furnished under the applicable standard rate schedule and this rider, filed as a special contract with the Commission for a fixed term of not less than ten (10) years and for such time thereafter under the terms stated in the standard rate schedule. A greater term of contract or termination notice may be required because of conditions associated with a Customer's requirements for service. Service will be continued under conditions provided for under the rate schedule to which this Rider is attached after the original term of contract.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 11, 2011

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2011-00103 dated August 11, 2011

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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. T
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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Second Revision of Original Sheet No. 79
Canceling P.S.C. Electric No. 9, First Revision of Original Sheet No. 79

Standard Rate

LEV
Low Emission Vehicle Service

APPLICABLE

In the territory served.

AVAILABILITY OF SERVICE

LEV shall be available as option to customers otherwise served under rate schedule RS to encourage off-peak power for low emission vehicles.

1) LEV is a three year pilot program that may be restricted to a maximum of one hundred (100) customers eligible for Rate RS (or GS where the GS service is used in conjunction with an RS service to provide service to a detached garage and energy usage is no more than 300 kWh per month) in any year and shall remain in effect until modified or terminated by order of the Commission. Company will accept applications on a first-come-first-served basis.
2) This service is restricted to customers who demonstrate power delivered to premises is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include:
    a) battery electric vehicles or plug-in hybrid electric vehicles recharged through a charging outlet at Customer's premises,
    b) natural gas vehicles refueled through an electric-powered refueling appliance at Customer's premises.
3) A customer exiting the pilot program or disconnected for non-payment may not be allowed to return to it until the Commission has issued a decision on the pilot program report.
4) Company will file a report on LEV with the Commission within six months after the first three years of implementation of the pilot program. Such report will detail findings and recommendations.

RATE

Basic Service Charge:	$10.75 per month
Plus an Energy Charge:	
Off Peak Hours:	$ 0.05820 per kWh
Intermediate Hours:	$ 0.07899 per kWh
Peak Hours:	$ 0.14451 per kWh

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Environmental Cost Recovery Surcharge	Sheet No. 87
Franchise Fee Rider	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

DATE OF ISSUE: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

LG&E Low Emission Vehicle Service Rate LEV is proposed to be eliminated.

Louisville Gas and Electric Company

Standard Rate **LEV**
Low Emission Vehicle Service

DETERMINATION OF PRICING PERIODS

Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends. The hours of the pricing periods for the price levels are as follows:

Summer months of May through September

	Off-Peak	Intermediate	Peak
Weekdays	10 PM - 10 AM	10 AM - 1 PM 7 PM - 10 PM	1 PM - 7 PM
Weekends	All Hours		

All other month of October continuously through April

	Off-Peak	Intermediate	Peak
Weekdays	10 PM - 6 AM	12 Noon – 10 PM	6 AM – 12 Noon
Weekends	All Hours		

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer’s payment will be due within 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 OF CONTRACT

For a fixed term of not less than one (1) year and for such time thereafter until terminated by either party giving thirty (30) days written notice to the other of the desire to terminate.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto. Customers served under this optional pilot program will not be eligible for Company’s Budget Payment Plan. Company shall install metering equipment capable of accommodating the Time of Use rate described herein.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

LG&E Low Emission Vehicle Service Rate LEV is proposed to be eliminated.

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 85
Canceling P.S.C. Electric No. 9, Original Sheet No. 85

Adjustment Clause **FAC**

Fuel Adjustment Clause

APPLICABLE.
In all territory service.

AVAILABILITY OF SERVICE
This schedule is mandatory to all electric rate schedules.

(1) The charge per kWh delivered under the rate schedules to which this fuel clause is applicable shall be increased or decreased during each month in accordance with the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where “F” is the expense of fossil fuel and “S” is the kWh sales in the base (b) and current (m) periods as defined in 807 KAR 5:056, all as set out below:

(2) Fuel costs (F) shall be the most recent actual monthly cost of:

(a) Fossil fuel consumed in the utility’s own plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation, plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute for the forced outages, plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) The cost of fossil fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(e) All fuel costs shall be based on weighted average inventory costing.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 85

Adjustment Clause **FAC**

Fuel Adjustment Clause

APPLICABLE.
In all territory service.

AVAILABILITY OF SERVICE
This schedule is mandatory to all electric rate schedules.

(1) The charge per kWh delivered under the rate schedules to which this fuel clause is applicable shall be increased or decreased during each month in accordance with the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where “F” is the expense of fossil fuel and “S” is the kWh sales in the base (b) and current (m) periods as defined in 807 KAR 5:056, all as set out below:

(2) Fuel costs (F) shall be the most recent actual monthly cost of:

(a) Fossil fuel consumed in the utility’s own plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation, plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute for the forced outages, plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) The cost of fossil fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(e) All fuel costs shall be based on weighted average inventory costing.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

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 April 2012 and the base fuel factor is $0.02725 per kWh.

(7) Current (m) period shall be the second month preceding the month in which the Fuel Clause Adjustment Factor is billed.

(8) Pursuant to the Public Service Commission's Orders in Case No. 2012-00553 dated May 17, 2013, and May 29, 2013, the Fuel Adjustment Clause will become effective with bills rendered on and after the first billing cycle for July 2013, which begins June 26, 2013.

DATE OF ISSUE: June 5, 2013

DATE EFFECTIVE: With Bills Rendered On and After
June 26, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the Public
Service Commission in Case No. 2012-00553
dated May 17, 2013 and May 29, 2013

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 April 2012 and the base fuel factor is $0.02725 per kWh.

(7) Current (m) period shall be the second month preceding the month in which the Fuel Clause Adjustment Factor is billed.

(8) Pursuant to the Public Service Commission's Orders in Case No. 2012-00553 dated May 17, 2013, and May 29, 2013, the Fuel Adjustment Clause will become effective with bills rendered on and after the first billing cycle for July 2013, which begins June 26, 2013.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: With Bills Rendered On and After
June 26, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of Orders of the Public
Service Commission in Case No. 2012-00553
dated May 17, 2013 and May 29, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 86
Canceling P.S.C. Electric No. 9, Original Sheet No. 86

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to Residential Rate RS, Volunteer Fire Department Rate VFD, General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Industrial Time-of-Day Primary Service Rate ITODP, Commercial Time-of-Day Primary Service Rate CTODP, Retail Transmission Service Rate RTS, and Low Emission Vehicle Service Rate LEV. Industrial customers who elect not to participate in a demand-side management program hereunder shall not be assessed a charge pursuant to this mechanism. For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are primarily engaged in a process or processes that create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32, and 33. All other non-residential customers will be defined as "commercial."

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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 Service Rate RTOD-Energy, Residential Time of Day Demand Service Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Service Rate RTS. 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:

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 86.1
Canceling P.S.C. Electric No. 9, 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, Volunteer Fire Department, General Service, and LEV customer classes is defined as the weighted average price per kWh of expected billings under the energy charges contained in the RS, VFD, GS, and LEV rate schedules in the upcoming twelve-month period after deducting the variable costs included in such energy charges. The non-variable revenue requirement for each of the customer classes that are billed under demand and energy rates (rate schedules PS, TODS, ITODP and CTODP) is defined as the weighted average price per kWh represented by the composite of the expected billings under the respective demand and energy charges in the upcoming twelve-month period, after deducting the variable costs included in the energy charges.

2) The lost revenues for each customer class shall then be divided by the estimated class sales (in kWh) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenue from lost sales calculated for a twelve-month period shall be included in the DRLS for thirty-six (36) months or until implementation of new rates pursuant to a general rate case, whichever comes first. Revenues from lost sales will be assigned for recovery purposes to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation, and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

DSMI = DSM INCENTIVE
For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved programs that are to be installed during the upcoming twelve-month period times fifteen (15) percent, not to exceed five (5) percent of program expenditures. Net resource savings are defined as program benefits less utility program costs and participant costs where program benefits will be calculated on the basis of the present value of Company's

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 T
Fire Department, and General Service customer classes is defined as the weighted T
average price per kWh of expected billings under the energy charges contained in
the RS, RTOD-Energy, VFD, and GS rate schedules in the upcoming twelve-month T
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, and T
RTS) is defined as the weighted average price per kWh represented by the T
composite of the expected billings under the respective demand and energy charges
in the upcoming twelve-month period, after deducting the variable costs included in
the energy charges.

2) The lost revenues for each customer class shall then be divided by the estimated class sales (in kWh) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenue from lost sales calculated for a twelve-month period shall be included in the DRLS for thirty-six (36) months or until implementation of new rates pursuant to a general rate case, whichever comes first. Revenues from lost sales will be assigned for recovery purposes to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation, and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

DSMI = DSM INCENTIVE
For all Energy Impact Programs except Direct Load Control, the DSM incentive amount
shall be computed by multiplying the net resource savings expected from the approved T

DATE OF ISSUE: November 26, 2014

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

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Canceling P.S.C. Electric No. 9, Original Sheet No. 86.2

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

avoided costs over the expected life of the program, and will include both capacity and energy savings. For the Energy Education Program, the DSM incentive amount shall be computed by multiplying the annual cost of the approved program times five (5) percent.

The DSM incentive amount related to programs for Residential Rate RS, Volunteer Fire Department Rate VFD, General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Industrial Time-of-Day Primary Service Rate ITODP, Commercial Time-of-Day Primary Service Rate CTODP, and Low Emission Vehicle Service Rate shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DSMI for such rate class. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

DBA = DSM BALANCE ADJUSTMENT

The DBA shall be calculated on a calendar-year basis and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, DCCR, and previous application of the DBA and the revenues that should have been billed, as follows:

1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.
2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.
3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.
4) For the DBA, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DBA and the balance adjustment amount established for the same twelve-month period.

The balance adjustment amounts determined on the basis of the above paragraphs (1)-(4) shall include interest applied to the monthly amounts, such interest to be calculated at a rate equal to the average of the "Three-Month Commercial Paper Rate" for the immediately preceding twelve-month period. The total of the balance adjustment amounts shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month period to determine the DBA for such rate class. DSM balance adjustment amounts will be assigned for recovery purposes to the rate classes for which over- or under-recoveries of DSM amounts were realized.

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State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 T
(15) percent, not to exceed five (5) percent of program expenditures. Net resource T
savings are defined as program benefits less utility program costs and participant costs T
where program benefits will be calculated on the basis of the present value of Company's T
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, T
Residential Time-of-Day Energy Service Rate RTOD-Energy, Residential Time-of-Day T
Demand Service Rate RTOD-Demand, Volunteer Fire Department Service Rate VFD, T
General Service Rate GS, Power Service Rate PS, Time-of-Day Secondary Service Rate
TODS, Time-of-Day Primary Service Rate TODP, and Retail Transmission Service Rate T
RTS shall be divided by the expected kilowatt-hour sales for the upcoming twelve-month T
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.

T

DATE OF ISSUE: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

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 (30) days prior to the effective period for billing. Each filing shall include the following information as applicable:

1) A detailed description of each DSM program developed by the collaborative process, the total cost of each program over the twelve-month period, an analysis of expected resource savings, information concerning the specific DSM or efficiency measures to be installed, and any applicable studies that have been performed, as available.
2) A statement setting forth the detailed calculation of the DCR, DRLS, DSMI, DBA, DCCR, and DSMRC.

Each change in the DSMRC shall be placed into effect with bills rendered on and after the effective date of such change.

DATE OF ISSUE: January 29, 2013

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ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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. T

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.
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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 (30) days prior to the effective period for billing. Each filing shall include the following information as applicable:

1) A detailed description of each DSM program developed by the collaborative process, the total cost of each program over the twelve-month period, an analysis of expected resource savings, information concerning the specific DSM or efficiency measures to be installed, and any applicable studies that have been performed, as available.
2) A statement setting forth the detailed calculation of the DCR, DRLS, DSMI, DBA, DCCR, and DSMRC.

Each change in the DSMRC shall be placed into effect with bills rendered on and after the effective date of such change.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 86.4
Canceling P.S.C. Electric No. 9, 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, VFD and LEV Standard Electric Rate Schedules.

Residential Load Management / Demand Conservation
The Residential Load Management / Demand Conservation Program employ switches in homes to help reduce the demand for electricity during peak times. The program communicates with the switches to cycle central air conditioning units, heat pumps, electric water heaters, and pool pumps off and on through a predetermined sequence. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

Residential Conservation / Home Energy Performance Program
The on-site audit offers a comprehensive audit from a certified auditor and incentives for residential customers to support the implementation of energy saving measures for a fee of $25. Customers are eligible for incentives of $500 or $1,000 based on customer purchased and installed energy efficiency measures and validated through a follow-up test.

Residential Low Income Weatherization Program (WeCare)
The Residential Low Income Weatherization Program (WeCare) is an education and weatherization program designed to reduce energy consumption of LG&E's low-income customers. The program provides energy audits, energy education, blower door tests, and installs weatherization and energy conservation measures. Qualified customers could receive energy conservation measures ranging from $0 to $2,100 based upon the customer's most recent twelve-month energy usage and results of an energy audit.

Smart Energy Profile
The Smart Energy Profile Program provides a portion of LG&E's highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar properties in locality. The report will help the customer understand and make better informed choices as it relates to energy usage and the associated costs. Information presented in the report will include a comparison of the customer's energy usage to that of similar houses (collectively) and a comparison to the customer's own energy usage in the prior year.

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

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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. T

Residential Load Management / Demand Conservation
The Residential Load Management / Demand Conservation Program employ switches in homes to help reduce the demand for electricity during peak times. The program communicates with the switches to cycle central air conditioning units, heat pumps, electric water heaters, and pool pumps off and on through a predetermined sequence. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

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DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 86.5

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Residential Incentives Program

The Residential Incentives Program encourages customers to purchase and install various ENERGY STAR® appliances, HVAC equipment, or window films that meet certain requirements, qualifying them for an incentive as noted in the table below.

Category	Item	Incentive
Appliances	Heat Pump Water Heaters (HPWH)	$300 per qualifying item purchased
	Washing Machine	$75 per qualifying item purchased
	Refrigerator	$100 per qualifying item purchased
	Freezer	$50 per qualifying item purchased
	Dishwasher	$50 per qualifying item purchased
Window Film	Window Film	Up to 50% of materials cost only; max of $200 per customer account; product must meet applicable criteria.
HVAC	Central Air Conditioner	$100 per Energy Star item purchased plus an additional $100 per SEER improvement above minimum
	Electric Air-Source Heat Pump	$100 per Energy Star item purchased plus additional $100 per SEER improvement above minimum

Residential Refrigerator Removal Program

The Residential Refrigerator Removal Program is designed to provide removal and recycling of working, inefficient secondary refrigerators and freezers from LG&E customer households. Customers participating in this program will be provided a one-time incentive. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

Residential High Efficiency Lighting Program

The Residential High Efficiency Lighting program promotes an increased use of ENERGY STAR® rated CFLs within the residential sector. The Residential High Efficiency Lighting Program distributes compact fluorescent bulbs through direct-mail.

Residential New Construction Program

The Residential New Construction program is designed to reduce residential energy usage and facilitate market transformation by creating a shift in builders' new home construction to include energy-efficient construction practices. Builders who are part of the program can take advantage of technical training classes, gain additional exposure to potential customers and receive incentives to help offset costs when including more energy-efficient features during home construction. LG&E will reimburse the cost of plan reviews and inspection costs related to an Energy Star or HERS home certification.

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

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Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

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ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Residential HVAC Diagnostics and Tune Up Program

The Residential HVAC Diagnostic and Tune-up program targets customers with HVAC system performance issues. There are no incentives paid directly to customers. Customers are charged a discounted, fixed-fee for the diagnosis and if needed, a similar fee for implementation of corrective actions. Thus, the program pays the portion of diagnostic and tune-up cost in excess of the customer charge below. The customer cost is as follows:

- Customer cost is $35 per unit for diagnostics test
- Customer cost is $50 per unit for tune-up

Customer Education and Public Information

These programs help customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through two processes: a mass-media campaign and an elementary- and middle-school program. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts.

Dealer Referral Network

The Dealer Referral Network assists customers in identifying qualified service providers to install energy efficiency improvements recommended and/ or subsidized by the various energy efficiency programs.

Commercial Customer Program Participation Incentives:

The following Demand Side Management programs are available to commercial customers receiving service from the Company on the GS, PS, TODS, CTODP, and RTS Standard Electric Rate Schedules.

Commercial Load Management / Demand Conservation

The Commercial Load Management / Demand Conservation Program employ switches or interfaces to customer equipment, in small and large commercial businesses to help reduce the demand for electricity during peak times. The Program communicates with the switches or interface to cycle equipment. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

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State Regulation and Rates
Louisville, Kentucky

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Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

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- Customer cost is $50 per unit for tune-up

Customer Education and Public Information

These programs help customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through two processes: a mass-media campaign and an elementary- and middle-school program. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts.

Dealer Referral Network

The Dealer Referral Network assists customers in identifying qualified service providers to install energy efficiency improvements recommended and/ or subsidized by the various energy efficiency programs.

Commercial Customer Program Participation Incentives:

The following Demand Side Management programs are available to commercial customers receiving service from the Company on the GS, PS, TODS, TODP, and RTS Standard Electric Rate Schedules. T

Commercial Load Management / Demand Conservation

The Commercial Load Management / Demand Conservation Program employ switches or interfaces to customer equipment, in small and large commercial businesses to help reduce the demand for electricity during peak times. The Program communicates with the switches or interface to cycle equipment. This program has an approved flexible incentive structure. The current program offering is defined on Sheet No 86.8.

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State Regulation and Rates
Louisville, Kentucky

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Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Commercial Conservation (Energy Audits) / Commercial Incentives

The Commercial Conservation / Commercial Inventive Program is designed to provide energy efficiency opportunities for the Companies' commercial class customers through energy audits and to increase the implementation of energy efficiency measures by providing financial incentives to assist with the replacement of aging and less efficient equipment. Incentives available to all commercial customers are based upon a $100 per kW removed for calculated efficiency improvements. A prescriptive list provides customers with incentive values for various efficiency improvements projects. Additionally, a custom rebate is available based upon company engineering validation of sustainable kW removed.

- Maximum annual incentive per facility is $50,000
- Customers can receive multi-year incentives in a single year where such multi-year incentives do not exceed the aggregate of $100,000 per facility and no incentive was provided in the immediately preceding year
- Applicable for combined Prescriptive and Custom Rebates

Commercial HVAC Diagnostics and Tune Up Program

The Commercial HVAC Diagnostic and Tune-up program targets customers with HVAC system performance issues. There are no incentives paid directly to customers. Customers are charged a discounted, fixed-fee for the diagnosis and if needed, a similar fee for implementation of corrective actions. Thus, the program pays the portion of diagnostic and tune-up cost in excess of the customer charge below. The customer cost is as follows:

- Customer cost is $50 per unit for diagnostics test
- Customer cost is $100 per unit for tune-up

Customer Education and Public Information

These programs help customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through two processes: a mass-media campaign and an elementary- and middle-school program. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts.

Dealer Referral Network

The Dealer Referral Network assists customers in identifying qualified service providers to install energy efficiency improvements recommended and/ or subsidized by the various energy efficiency programs.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 86.7

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Commercial Conservation (Energy Audits) / Commercial Incentives

The Commercial Conservation / Commercial Inventive Program is designed to provide energy efficiency opportunities for the Companies' commercial class customers through energy audits and to increase the implementation of energy efficiency measures by providing financial incentives to assist with the replacement of aging and less efficient equipment. Incentives available to all commercial customers are based upon a $100 per kW removed for calculated efficiency improvements. A prescriptive list provides customers with incentive values for various efficiency improvements projects. Additionally, a custom rebate is available based upon company engineering validation of sustainable kW removed.

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Dealer Referral Network

The Dealer Referral Network assists customers in identifying qualified service providers to install energy efficiency improvements recommended and/ or subsidized by the various energy efficiency programs.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S. C. Electric No. 9, Third Revision of Original Sheet No. 86.8
Canceling P.S.C. Electric No. 9, Second Revision of Original Sheet No. 86.8

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

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.

Current Program Incentive Structures

Residential Load Management / Demand Conservation
Switch Option:

- $5/month bill credit for June, July, August, & September per air conditioning unit or heat pump on single family home.
- $2/month bill credit for June, July, August, & September per electric water heater (40 gallon minimum) or swimming pool pump on single family home.
- If new customer registers by May 31, 2014, then a $25 gift card per air-conditioning unit, heat pump, water-heater (40 gallon minimum) and/or swimming pool pump switch installed.
  - Customers in a tenant landlord relationship will receive the entire $25 new customer incentive.

Multi-family Option:

- Tenant - $2/month bill credit per customer for June, July, August, & September per air conditioning unit, heat pump, or water heater (40 gallon minimum).
- Entire Complex Enrollment – Property owner receives $2/month incentive per air conditioning or heat pump switch to the premise owner for June, July, August, & September.
- If new customer registers by May 31, 2014, then a $25 gift card per air-conditioning unit or heat pump installed, where:
  - Customers in a tenant/property owner relationship where the entire complex participates, the property owner will receive a $25 bonus incentive per air conditioning unit, heat pump, or water heater (40 gallon minimum).
  - Customers in a tenant landlord relationship where only a portion of the complex participates, the tenant will receive a $25 gift card new customer incentive.

Residential Refrigerator Removal Program
The program provides $50 per working refrigerator or freezer.

DATE OF ISSUE: November 27, 2013

DATE EFFECTIVE: December 31, 2013

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 86.8

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

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- If new customer registers by May 31, 2014, then a $25 gift card per air-conditioning unit, heat pump, water-heater (40 gallon minimum) and/or swimming pool pump switch installed.
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- If new customer registers by May 31, 2014, then a $25 gift card per air-conditioning unit or heat pump installed, where:
  - Customers in a tenant/property owner relationship where the entire complex participates, the property owner will receive a $25 bonus incentive per air conditioning unit, heat pump, or water heater (40 gallon minimum).
  - Customers in a tenant landlord relationship where only a portion of the complex participates, the tenant will receive a $25 gift card new customer incentive.

Residential Refrigerator Removal Program
The program provides $50 per working refrigerator or freezer.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: December 31, 2013

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 86.9
Canceling P.S.C. Electric No. 9, Original Sheet No. 86.9

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Commercial Load Management / Demand Conservation

Switch Option

- $5 per month bill credit for June, July, August, & September for air conditioning units up to 5 tons. An additional $1 per month bill credit for each additional ton of air conditioning above 5 tons based upon unit rated capacity.

Customer Equipment Interface Option

The Company will offer a Load Management / Demand Response program tailored to a commercial customer's ability to reduce load. Program participants must commit to a minimum of 50 kW demand reduction per control event. The Company will continue to enroll program participants until 10MW curtailable load is achieved.

- $25 per kW for verified load reduction during June, July, August, & September.
- The customer will have access to at least hourly load data for every month of the year which they remain enrolled in the program.
- Additional customer charges may be incurred for metering equipment necessary for this program at costs under other tariffs.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: May 31, 2012

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 86.9

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Commercial Load Management / Demand Conservation

Switch Option

- $5 per month bill credit for June, July, August, & September for air conditioning units up to 5 tons. An additional $1 per month bill credit for each additional ton of air conditioning above 5 tons based upon unit rated capacity.

Customer Equipment Interface Option

The Company will offer a Load Management / Demand Response program tailored to a commercial customer's ability to reduce load. Program participants must commit to a minimum of 50 kW demand reduction per control event. The Company will continue to enroll program participants until 10MW curtailable load is achieved.

- $25 per kW for verified load reduction during June, July, August, & September.
- The customer will have access to at least hourly load data for every month of the year which they remain enrolled in the program.
- Additional customer charges may be incurred for metering equipment necessary for this program at costs under other tariffs.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: May 31, 2012

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Fourth Revision of Original Sheet No. 86.10
Canceling P.S.C. Electric No. 9, Third Revision of Original Sheet No. 86.10

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Residential Rate RS, Volunteer Fire Department Rate VFD, and Low Emission Vehicle Service Rate LEV	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00192 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00144 per kWh
DSM Incentive (DSMI)	$ 0.00009 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00106 per kWh
DSM Balance Adjustment (DBA)	$ 0.00092 per kWh
Total DSMRC for Rates RS, VFD, and LEV	$ 0.00543 per kWh

General Service Rate GS	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00089 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00199 per kWh
DSM Incentive (DSMI)	$ 0.00004 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00004 per kWh
DSM Balance Adjustment (DBA)	$ 0.00007 per kWh
Total DSMRC for Rate GS	$ 0.00303 per kWh

Commercial Customers Served Under Power Service Rate PS	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00033 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00066 per kWh
DSM Incentive (DSMI)	$ 0.00002 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00011 per kWh
DSM Balance Adjustment (DBA)	$ 0.00027 per kWh
Total DSMRC for Rate PS	$ 0.00139 per kWh

Commercial Customers Served Under Time-of-Day Secondary Service Rate TODS and Commercial Time-of-Day Primary Service Rate CTODP	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00025 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00046 per kWh
DSM Incentive (DSMI)	$ 0.00001 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00002 per kWh
DSM Balance Adjustment (DBA)	$ 0.00002 per kWh
Total DSMRC for Rates TODS, and CTODP	$ 0.00076 per kWh

DATE OF ISSUE: February 28, 2014

DATE EFFECTIVE: April 1, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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	T
DSM Cost Recovery Component (DCR)	$ 0.00192 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00144 per kWh	
DSM Incentive (DSMI)	$ 0.00009 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00106 per kWh	
DSM Balance Adjustment (DBA)	$ 0.00092 per kWh	
Total DSMRC for Rates RS, RTOD-Energy, RTOD-Demand, and VFD	$ 0.00543 per kWh	T

General Service Rate GS*	Energy Charge	T
DSM Cost Recovery Component (DCR)	$ 0.00089 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00199 per kWh	
DSM Incentive (DSMI)	$ 0.00004 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00004 per kWh	
DSM Balance Adjustment (DBA)	$ 0.00007 per kWh	
Total DSMRC for Rate GS	$ 0.00303 per kWh	

Power Service Rate PS*	Energy Charge	T
DSM Cost Recovery Component (DCR)	$ 0.00033 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00066 per kWh	
DSM Incentive (DSMI)	$ 0.00002 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00011 per kWh	
DSM Balance Adjustment (DBA)	$ 0.00027 per kWh	
Total DSMRC for Rate PS	$ 0.00139 per kWh	

Time-of-Day Secondary Service Rate TODS*, Time-of-Day Primary Service Rate TODP*, and Retail Transmission Service Rate RTS*	Energy Charge	T
DSM Cost Recovery Component (DCR)	$ 0.00025 per kWh	
DSM Revenues from Lost Sales (DRLS)	$ 0.00046 per kWh	
DSM Incentive (DSMI)	$ 0.00001 per kWh	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00002 per kWh	
DSM Balance Adjustment (DBA)	$ 0.00002 per kWh	
Total DSMRC for Rates TODS, and TODP	$ 0.00076 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. T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors

Industrial Customers Served Under Power Service Rate PS, Time-of-Day Secondary Service Rate TODS, Industrial Time-of-Day Primary Service Rate ITODP, and Retail Transmission Rate RTS	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00000 per kWh
DSM Revenues from Lost Sales (DRLS)	$ 0.00000 per kWh
DSM Incentive (DSMI)	$ 0.00000 per kWh
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per kWh
DSM Balance Adjustment (DBA)	$ 0.00000 per kWh
Total DSMRC for Rates PS, TODS, ITODP, and RTS	$ 0.00000 per kWh

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

LG&E Demand-Side Management Cost Recovery Mechanism is now contained on eleven pages instead of the current twelve pages.

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 87
Canceling P.S.C. Electric No. 9, Original Sheet No. 87

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except CTAC and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC and DSM Adjustment Clauses. Standard Electric Rate Schedules subject to this schedule are divided into Group 1 or Group 2 as follows:

Group 1: Rate Schedules RS; VFD; LS; RLS; LE; TE; and Pilot Program LEV.
Group 2: Rate Schedules GS; PS; TODS; ITODP; CTODP; RTS; and FLS.

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: December 3, 2013

DATE EFFECTIVE: With Bills Rendered On and After
December 31, 2013

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2013-00243 dated November 14, 2013

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 87

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to all Standard Electric Rate Schedules listed in Section 1 of the General Index except CTAC and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC and DSM Adjustment Clauses. Standard Electric Rate Schedules subject to this schedule are divided into Group 1 or Group 2 as follows:

Group 1: Rate Schedules RS; RTOD-Energy; RTOD-Demand; VFD; LS; RLS; LE; and TE. T
Group 2: Rate Schedules GS; PS; TODS; TODP; RTS; and FLS. T

RATE

The monthly billing amount under each of the schedules to which this mechanism is applicable, shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

Group Environmental Surcharge Billing Factor = Group E(m) / Group R(m)

As set forth below, Group E(m) is the sum of Jurisdictional E(m) of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the 12-month average revenue for the current expense month and for Group 2 it is the 12-month average non-fuel revenue for the current expense month.

DEFINITIONS

1) For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – EAS + BR
   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: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 87.1

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor. Jurisdictional E(m) is adjusted for any (Over)/Under collection or prior period adjustment and by the subtraction of the Revenue Collected through Base Rates for the Current Expense month to arrive at Adjusted Net Jurisdictional E(m). Adjusted Net Jurisdictional E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the 12 months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).

3) The Group 1 R(m) is the average of total Group 1 monthly base revenue for the 12 months ending with the current expense month. Base revenue includes the customer, energy, and lighting charges for each rate schedule included in Group 1 to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.

4) The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the 12 months ending with the current expense month. Base non-fuel revenue includes the customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this mechanism is applicable and automatic adjustment clause revenues for the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6.

5) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 87.1

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

<u>DEFINITIONS (continued)</u> T

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor. Jurisdictional E(m) is adjusted for any (Over)/Under collection or prior period adjustment and by the subtraction of the Revenue Collected through Base Rates for the Current Expense month to arrive at Adjusted Net Jurisdictional E(m). Adjusted Net Jurisdictional E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the 12 months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m).

3) The Group 1 R(m) is the average of total Group 1 monthly base revenue for the 12 months ending with the current expense month. Base revenue includes the customer, energy, and lighting charges for each rate schedule included in Group 1 to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.

4) The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the 12 months ending with the current expense month. Base non-fuel revenue includes the customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this mechanism is applicable and automatic adjustment clause revenues for the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6.

5) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 90
Canceling P.S.C. Electric No. 9, Original Sheet No. 90

Adjustment Clause **FF**
Franchise Fee Rider

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available as an option for collection of revenues within governmental jurisdictions which impose on Company franchise fees, permitting fees, local taxes or other charges by ordinance, franchise, or other governmental directive and not otherwise collected in the charges of Company's base rate schedules.

DEFINITIONS

Base Year - the twelve-month period ending November 30.
Collection Year - the full calendar year following the Base Year.
Base Year Amount -

1) a percentage of revenues, as determined in the franchise agreement, for the Base Year; and
2) License fees, permit fees, or other costs specifically borne by Company for the purpose of maintaining the franchise as incurred in the Base Year and applicable specifically to Company by ordinance or franchise for operation and maintenance of its facilities in the franchise area, including but not limited to costs incurred by Company as a result of governmental regulation or directives requiring construction or installation of facilities beyond that normally provided by Company in accordance with applicable Rules and Regulations approved by and under the direction of the Kentucky Public Service Commission; and
3) any adjustment for over or under collection of revenues associated with the amounts in 1) or 2).

RATE

The franchise percentage will be calculated by dividing the Base Year amount by the total revenues in the Base Year for the franchise area. The franchise percentage will be monitored during the Collection Year and adjusted to recover the Base Year Amount in the Collection Year as closely as possible.

BILLING

1) The franchise charge will be applied exclusively to the base rate and all riders of bills of customers receiving service within the franchising governmental jurisdiction, before taxes.
2) The franchise charge will appear as a separate line item on the Customer's bill and show the unit of government requiring the franchise.
3) Payment of the collected franchise charges will be made to the governmental franchising body as agreed to in the franchise agreement.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: October 16, 2003

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: October 16, 2003

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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: January 31, 2013

DATE EFFECTIVE: October 16, 2003

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: October 16, 2003

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 91

Adjustment Clause **ST**
School Tax

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is applied as a rate increase to all other schedules pursuant to KRS 160.617 for the recovery by the utility of school taxes in any county requiring a utility gross receipts license tax for schools under KRS 160.613.

RATE
The utility gross receipts license tax authorized under state law.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 91

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 92

Adjustment Clause **HEA**
Home Energy Assistance Program

APPLICABLE
In all territory served.

AVAILABILITY
To all residential customers.

RATE
$0.25 per meter per month.

BILLING
The HEA charge shall be shown as a separate item on customer bills.

SERVICE PERIOD
The Home Energy Assistance charge will be applied to all residential electric bills rendered during the billing cycles commencing January 1, 2013 until the effective date of new base rates, or as otherwise directed by the Public Service Commission. The HEA program is approved through September 30, 2015. 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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 92

Adjustment Clause **HEA**
Home Energy Assistance Program

APPLICABLE
In all territory served.

AVAILABILITY
To all residential customers.

RATE
$0.25 per meter per month.

BILLING
The HEA charge shall be shown as a separate item on customer bills.

SERVICE PERIOD
The Home Energy Assistance charge will be applied to all residential electric bills rendered during the billing cycles commencing January 1, 2013 until the effective date of new base rates, or as otherwise directed by the Public Service Commission. The HEA program is approved through September 30, 2015. 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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 95

TERMS AND CONDITIONS
Customer Bill of Rights

As a residential customer of a regulated public utility in Kentucky, you are guaranteed the following rights subject to Kentucky Revised Statutes and the provisions of the Kentucky Public Service Commission Administrative Regulations:

- You have the right to service, provided you (or a member of your household whose debt was accumulated at your address) are not indebted to the utility.
- You have the right to inspect and review the utility's rates and tariffed operating procedures during the utility's normal office hours.
- You have the right to be present at any routine utility inspection of your service conditions.
- You must be provided a separate, distinct disconnect notice alerting you to a possible disconnection of your service, if payment is not received.
- You have the right to dispute the reasons for any announced termination of your service.
- You have the right to negotiate a partial payment plan when your service is threatened by disconnection for non-payment.
- You have the right to participate in equal, budget payment plans for your natural gas and electric service.
- You have the right to maintain your utility service for up to thirty (30) days upon presentation of a medical certificate issued by a health official.
- You have the right to prompt (within 24 hours) restoration of your service when the cause for discontinuance has been corrected.
- If you have not been disconnected, you have the right to maintain your natural gas and electric service for up to thirty (30) days, provided you present a Certificate of Need issued by the Kentucky Cabinet for Human Resources between the months of November and the end of March.
- If you have been disconnected due to non-payment, you have the right to have your natural gas or electric service reconnected between the months of November through March provided you:
  1) Present a Certificate of Need issued by the Kentucky Cabinet for Human Resources, and
  2) Pay one third (1/3) of your outstanding bill ($200 maximum), and
  3) Accept referral to the Human Resources' Weatherization Program, and
  4) Agree to a repayment schedule that will cause your bill to become current by October 15.
- You have the right to contact the Public Service Commission regarding any dispute that you have been unable to resolve with your utility (call Toll Free 1-800-772-4636).

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 95

TERMS AND CONDITIONS

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

All electric service supplied by Company shall be in accordance with the applicable rules and regulations of the Public Service Commission of Kentucky.

COMPANY TERMS AND CONDITIONS.

In addition to the rules and regulations of the Commission, all electric service supplied by Company shall be in accordance with these Terms and Conditions, which shall constitute a part of all applications and contracts for service.

RATES, TERMS AND CONDITIONS ON FILE

A copy of the rate schedules, terms, and conditions under which electric service is supplied is on file with the Public Service Commission of Kentucky. A copy of such rate schedules, terms and conditions, together with the law, rules, and regulations of the Commission, is available for public inspection in each office of Company where bills may be paid.

ASSIGNMENT

No order for service, agreement or contract for service may be assigned or transferred without the written consent of Company.

RENEWAL OF CONTRACT

If, upon the expiration of any service contract for a specified term, the customer continues to use the service, the contract (unless otherwise provided therein) will be automatically renewed for successive periods of one (1) year each, subject to termination at the end of any year upon thirty (30) days prior written notice by either party.

AGENTS CANNOT MODIFY AGREEMENT WITHOUT CONSENT OF P.S.C. OF KY.

No agent has power to amend, modify, alter, or waive any of these Terms and Conditions, or to bind Company by making any promises or representations not contained herein.

SUPERSEDE PREVIOUS TERMS AND CONDITIONS

These Terms and Conditions supersede all terms and conditions under which Company has previously supplied electric service.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: February 6, 2009

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

All electric service supplied by Company shall be in accordance with the applicable rules and regulations of the Public Service Commission of Kentucky.

COMPANY TERMS AND CONDITIONS.

In addition to the rules and regulations of the Commission, all electric service supplied by Company shall be in accordance with these Terms and Conditions, which shall constitute a part of all applications and contracts for service.

COMPANY AS A FEDERAL CONTRACTOR T

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.

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

LG&E TERMS and CONDITIONS – General is now contained on two pages instead of the current one page.

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 96.1

TERMS AND CONDITIONS

T

General

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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.

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These Terms and Conditions supersede all terms and conditions under which Company has previously supplied electric service.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

A written application or contract, properly executed, may be required before Company is obligated to render electric service. Company shall have the right to reject for valid reasons any such application or contract.

All applications for service shall be made in the legal name of the party desiring the service.

Where an unusual expenditure for construction or equipment is necessary or where the proposed manner of using electric service is clearly outside the scope of Company's standard rate schedules, Company may establish special contracts giving effect to such unusual circumstances. Customer accepts that non-standard service may result in the delay of required maintenance or, in the case of outages, restoration of service.

TRANSFER OF APPLICATION

Applications for electric service are not transferable and new occupants of premises will be required to make application for service before commencing the use of electricity. Customers who have been receiving electric service shall notify Company when discontinuance of service is desired, and shall pay for all electric service furnished until such notice has been given and final meter readings made by Company.

CONTRACTED DEMANDS

For rate applications where billing demand minimums are determined by the Contract Demand customer shall execute written Contract prior to rendering of service. At Company’s sole discretion, in lieu of a written contract, a completed load data sheet or other written load specification, as provided by Customer, can be used to determine the maximum load on Company’s system for determining Contract Demand minimum.

OPTIONAL RATES

If two or more rate schedules are available for the same class of service, it is Customer’s responsibility to determine the options available and to designate the schedule under which customer desires to receive service.

Company will, at any time, upon request, advise any customer as to the most advantageous rate for existing or anticipated service requirements as defined by Customer, but Company does not assume responsibility for the selection of such rate or for the continuance of the lowest annual cost under the rate selected.

In those cases in which the most favorable rate is difficult to predetermine, Customer will be given the opportunity to change to another schedule, unless otherwise prevented by the rate schedule under which Customer is currently served, after trial of the schedule originally designated; however, after the first such change, Company shall not be required to make a change in schedule more often than once in twelve months.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

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State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

Customer Responsibilities

From time to time, Customer should investigate Customer’s operating conditions to determine a desirable change from one available rate to another. Company, lacking knowledge of changes that may occur at any time in Customer's operating conditions, does not assume responsibility that customers will at all times be served under the most beneficial rate.

In no event will Company make refunds covering the difference between the charges under the rate in effect and those under any other rate applicable to the same class of service.

CUSTOMER’S EQUIPMENT AND INSTALLATION

Customer shall furnish, install and maintain at Customer’s expense all electrical apparatus and wiring to connect with Company's service drop or service line. All such apparatus and wiring shall be installed and maintained in conformity with applicable statutes, laws or ordinances and with the rules and regulations of the constituted authorities having jurisdiction. Customer shall not install wiring or connect and use any motor or other electricity-using device which in the opinion of Company is detrimental to its electric system or to the service of other customers of Company. Company assumes no responsibility whatsoever for the condition of Customer's electrical wiring, apparatus, or appliances, nor for the maintenance or removal of any portion thereof.

In the event Customer builds or extends its own transmission or distribution system over property Customer owns, controls, or has rights to, and said system extends or may extend into the service territory of another utility company, Customer will notify Company of their intention in advance of the commencement of construction.

OWNER'S CONSENT TO OCCUPY

Customer shall grant easements and rights-of-way on and across Customer's property at no cost to Company.

ACCESS TO PREMISES AND EQUIPMENT

Company shall have the right of access to Customer's premises at all reasonable times for the purpose of installing, meter reading, inspecting, repairing, or removing its equipment used in connection with its supply of electric service or for the purpose of turning on and shutting off the supply of electricity when necessary and for all other proper purposes. Customer shall not construct or permit the construction of any structure or device which will restrict the access of Company to its equipment for any of the above purposes.

PROTECTION OF COMPANY'S PROPERTY

Customers will be held responsible for tampering, interfering with, breaking of seals of meters, or other equipment of Company installed on Customer's premises, and will be held liable for same according to law. Customer hereby agrees that no one except the employees of Company shall be allowed to make any internal or external adjustments of any meter or any other piece of apparatus which shall be the property of Company.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Customer Responsibilities

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S. C. Electric No. 9, First Revision of Original Sheet No. 97.2
Canceling P.S.C. Electric No. 9, Original Sheet No. 97.2

TERMS AND CONDITIONS

Customer Responsibilities

POWER FACTOR

Company installs facilities to supply power to its customers at or near unity power factor.

Company expects any customer to use apparatus which shall result in a power factor near unity However, Company will permit the use of apparatus which shall result, during normal operation, in a power factor not lower than 90 percent either lagging or leading.

Where Customer's power factor is less than 90 percent, Company reserves the right to require the customer to furnish, at Customer's own expense, suitable corrective equipment to maintain a power factor of 90 percent or higher.

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

Except in cases where Customer has contracted with Company for reserve or auxiliary service, no other electric light or power service will be used by Customer on the same installation in conjunction with Company's service, either by means of a throw-over switch or any other connection.

LIABILITY

Customer assumes all responsibility for the electric service upon Customer's premises at and from the point of delivery of electricity and for the wires and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of electricity, occasioned by such electricity or said wires and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence of Company.

NOTICE TO COMPANY OF CHANGES IN CUSTOMER'S LOAD

The service connections, transformers, meters, and appurtenances supplied by Company for the rendition of electric service to its customers have a definite capacity which may not be exceeded without damage. In the event that Customer contemplates any material increase in Customer's connected load, whether in a single increment or over an extended period, Customer shall immediately give Company written notice of this fact so as to enable it to enlarge the capacity of such equipment. In case of failure to give such notice, Customer may be held liable for any damage done to meters, transformers, or other equipment of Company caused by such material increase in the Customer's connected load. Should Customer make a permanent change in the operation of electrical equipment that materially reduces the maximum load required by Customer, Company may reduce Customer's contract capacity.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No.10, Original Sheet No. 97.2

TERMS AND CONDITIONS

Customer Responsibilities

POWER FACTOR

Company installs facilities to supply power to its customers at or near unity power factor.

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 97.3
Canceling P.S.C. Electric No. 9, Original Sheet No. 97.3

TERMS AND CONDITIONS

Customer Responsibilities

PERMITS

Customer shall obtain or cause to be obtained all permits, easements, or certificates, except street permits, necessary to give Company or its agents access to Customer's premises and equipment and to enable its service to be connected therewith. In case Customer is not the owner of the premises or of intervening property between the premises and Company's distribution lines, 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 the customer.

Company shall make or cause to be made application for any necessary street permits, and shall not be required to supply service under Customer's application until a reasonable time after such permits are granted.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 97.3

TERMS AND CONDITIONS

Customer Responsibilities

PERMITS

Customer shall obtain or cause to be obtained all permits, easements, or certificates, except street permits, necessary to give Company or its agents access to Customer's premises and equipment and to enable its service to be connected therewith. In case Customer is not the owner of the premises or of intervening property between the premises and Company's distribution lines, 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 the customer.

Company shall make or cause to be made application for any necessary street permits, and shall not be required to supply service under Customer's application until a reasonable time after such permits are granted.

CHANGES IN SERVICE T
Where Customer is receiving service and desires relocation or change in facilities not supported T
by additional load, Customer is responsible for the cost of the relocation or change in facilities T
through a Non-Refundable Advance. T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 98
Canceling P.S.C. Electric No. 9, Original Sheet No. 98

TERMS AND CONDITIONS

Company Responsibilities

METERING

The electricity used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

POINT OF DELIVERY OF ELECTRICITY

The point of delivery of electrical energy supplied by Company shall be at the point, as designated by Company, where Company's facilities are connected with the facilities of Customer, irrespective of the location of the meter

EXTENSION OF SERVICE

The main transmission lines of Company, or branches thereof, will be extended to such points as provide sufficient load to justify such extensions or in lieu of sufficient load, Company may require such definite and written guarantees from a customer, or group of customers, in addition to any minimum payments required by the Tariff as may be necessary. This requirement may also be made covering the repayment, within a reasonable time, of the cost of tapping such existing lines for light or power service or both.

COMPANY'S EQUIPMENT AND INSTALLATION

Company will furnish, install, and maintain at its expense the necessary overhead service drop or service line required to deliver electricity at the voltage contracted for, to Customer's electric facilities.

Company will furnish, install, and maintain at its expense the necessary meter or meters. (The term meter as used here and elsewhere in these rules and regulations shall be considered to include all associated instruments and devices, such as current and potential transformers installed for the purpose of measuring deliveries of electricity to the customer.) Suitable provision for Company's meter, including an adequate protective enclosure for the same if required, shall be made by Customer. Title to the meter shall remain 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.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: February 6, 2009

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 98

TERMS AND CONDITIONS

Company Responsibilities

METERING

The electricity used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 98.1
Canceling P.S.C. Electric No. 9, 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 Customer's use of Company's service causes damage to Company's property or injuries to persons, Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

FIRM SERVICE
Where a customer-generator supplies all or part of the customer-generator's own load and desires Company to provide supplemental or standby service for that load, the customer-generator must contract for such service under Company's Supplemental or Standby Service Rider, otherwise Company has no obligation to supply the non-firm service. This requirement does not apply to Net Metering Service (Rider NMS).

DATE OF ISSUE: January 31, 2013

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 98.1

TERMS AND CONDITIONS

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 99

TERMS AND CONDITIONS

Character of Service

Electric service, under the rate schedule herein, will be 60 cycle, alternating current delivered from Company’s various load centers and distribution lines at typical nominal voltages and phases, as available in a given location, as follows:

SECONDARY VOLTAGES
Residential Service -
Single phase 120/240 volts three-wire service or 120/208Y volts three-wire service where network system is available.
Non-Residential Service -
1) Single phase 120/240 volts three-wire service or 120/208Y three-wire service where network system is available.
2) Three phase 240 volts three-wire, 480 volts three-wire service, 120/208Y volts four-wire service, or 277/480Y volts four-wire service.

PRIMARY VOLTAGES
According to location, 2400/4160Y volts, 7200/12,470Y volts, 13,800 volts, or 34,500 volts.

TRANSMISSION VOLTAGES
According to location, 69,000 volts, 138,000 volts, or 345,000 volts.

The voltage available to any individual customer shall depend upon the voltage of Company's lines serving the area in which such customer's electric load is located.

RESTRICTIONS

1. Except for minor loads, with approval of the Company, two-wire service is restricted to those customers on service July 1, 2004.
2. To be eligible for the rate applicable to any delivery voltage other than secondary voltage, a customer must furnish and maintain complete substation structure, transformers, and other equipment necessary to take service at the primary or transmission voltage available at point of connection.
   a) In the event Company is required to provide transformation to reduce an available voltage to a lower voltage for delivery to Customer, Customer shall be served at the rate applicable to the lower voltage; provided, however, that if the same rate is applicable to both the available voltage and the delivery voltage, Customer may be required to make a non-refundable payment to reflect the additional investment required to provide service.
   b) The available voltage shall be the voltage on that distribution or transmission line which the Company designates as being suitable from the standpoint of capacity and other operating characteristics for supplying the requirements of Customer.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 99

TERMS AND CONDITIONS

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1) Single phase 120/240 volts three-wire service or 120/208Y three-wire service where network system is available.
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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 100
Canceling P.S.C. Electric No. 9, Original Sheet No. 100

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

Residential electric service is available for uses customarily associated with residential occupation, including lighting, cooking, heating, cooling, refrigeration, household appliances, and other domestic purposes.

1. Residential rates are based on service to single family units and are not applicable to multi-family dwellings served through a single meter. Where two or more families occupy a residential building, Company will require, as a condition precedent to the application of the residential rate, that the wiring in the building be so arranged as to permit each family to be served through a separate meter. In those cases where such segregation of wiring would involve undue expense to Customer, Company will allow service to two or more families to be taken through one meter, but in this event the minimum bills of the applicable residential rate shall be multiplied by the number of families thus served, such number of families to be determined on the basis of the number of kitchens in the building. At Customer's option, in lieu of the foregoing, electric service rendered to a multi-family residential building through a single meter will be classified as commercial and billed on the basis of service to one customer at an appropriate non-residential rate.

2. Single family unit service shall include usage of electric energy customarily incidental to home occupations, such as the office of a physician, surgeon, dentist, musician or artist when such occupation is carried on by Customer in his residence.

3. A residential building used by a single family as a home, which is also used to accommodate roomers or boarders for compensation, will be billed at the residential rate provided it does not exceed twelve (12) rooms in size. Such a residential building of more than twelve (12) rooms used to accommodate roomers or borders for compensation will be classified as commercial and billed on the appropriate rate. In determining the room rating of rooming and boarding houses, all wired rooms shall be counted except hallways, vestibules, alcoves, closets, bathrooms, lavatories, garrets, attics, storage rooms, trunk rooms, basements, cellars, porches and private garages.

4. Service used in residential buildings occupied by fraternity or sorority organizations associated with educational institutions will be classified as residential and billed at the residential rate.

5. Where both residential and general or commercial classes of service are supplied through a single meter, such combined service shall be billed at the appropriate non-residential rate. Customer may arrange his wiring so as to separate the general service from the residential service, in which event two (2) meters will be installed by Company and separate residential and general service rates applied to the respective classes of service.

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 his 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. T

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 Rate RS when measured through the residential meter subject to the conditions set forth below:

   (a) Single-phase motors may be served at 120 volts if the locked-rotor current at rated voltage does not exceed 50 amperes. Motors with locked-rotor current ratings in excess of 50 amperes must be served at 240 volts.

   (b) Single-phase motors of new central residential cooling installations with total locked-rotor ratings of not to exceed 125 amperes (inclusive of any auxiliary motors arranged for simultaneous starting with the compressor) may be connected for across-the-line starting provided the available capacity of Company's electric distribution facilities at desired point of supply is such that, in Company's judgment, the starting of such motors will not result in excessive voltage dips and undue disturbance of lighting service and television reception of

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

6. If Customer's barns, pump house or other outbuildings are located at such distance from his residence as to make it impracticable to supply service thereto through his residential meter, the separate meter required to measure service to such remotely located buildings will be considered a separate service contract and billed as a separate customer on the applicable non-residential rate.

7. Single-phase power service used for domestic purposes will be permitted under Residential Rate RS when measured through the residential meter subject to the conditions set forth below:

   (a) Single-phase motors may be served at 120 volts if the locked-rotor current at rated voltage does not exceed 50 amperes. Motors with locked-rotor current ratings in excess of 50 amperes must be served at 240 volts.

   (b) Single-phase motors of new central residential cooling installations with total locked-rotor ratings of not to exceed 125 amperes (inclusive of any auxiliary motors arranged for simultaneous starting with the compressor) may be connected for across-the-line starting provided the available capacity of Company's electric distribution facilities at desired point of supply is such that, in Company's judgment, the starting of such motors will not result in excessive voltage dips and undue disturbance of lighting service and television reception of nearby electric customers. However, except with Company's express written consent, no new single-phase central residential cooling unit having a total lock-rotor rating in excess of 125 amperes inclusive of auxiliary motors arranged for simultaneous starting with the compressor) shall hereafter be connected to Company's lines, or be eligible for electric service therefrom, unless it is equipped with an approved type of current-limiting device for starting which will reduce the initial and incremental starting current inrush to a maximum of 100 amperes per step. Company shall be furnished with reasonable advance notice of any proposed central residential cooling installation.

   (c) In the case of multi-motored devices arranged for sequential starting of the motors, the above rules are considered to apply to the locked-rotor currents of the individual motors; if arranged for simultaneous starting of the motors, the rules apply to the sum of the locked-rotor currents of all motors so started.

   (d) Any motor or motors served through a separate meter will be billed as a separate customer.

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TERMS AND CONDITIONS

Residential Rate Specific Terms and Conditions

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 101
Canceling P.S.C. Electric No. 9, Original Sheet No. 101

TERMS AND CONDITIONS

BILLING

METER READINGS AND BILLS

Each bill for utility service shall be issued in compliance with 807 KAR 5:006, Section 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 meters at least quarterly, except that customer-read meters shall be read at least once during the calendar year.

In the case of opening and closing bills when the total period between regular and special meter readings is less than thirty days, the minimum charges of the applicable rate schedules will be prorated on the basis of the ratio of the actual number of days in such period to thirty days.

When Company is unable to read Customer's meter after reasonable effort, or when Company experiences circumstances which make actual meter readings impossible or impracticable, Customer may be billed on an estimated basis and the billing will be adjusted as necessary when the meter is read.

In the event Company's meter fails to register properly by reason of damage, accident, etc., Company shall have the right to estimate Customer's consumption during the period of failure on the basis of such factors as Customer's connected load, heating degree days, and consumption during a previous corresponding period and during a test period immediately following replacement of the defective meter.

Where Company serves a customer with both electric and gas service at the same service location, Company will render a combined bill. Provided, however, a residential customer may request, and Company will render, separate bills under the following conditions: (1) Customer is being threatened with disconnection for non-payment or has already been disconnected for that reason and (2) Customer would be able to pay either the gas or electric portion of his bill and thus retain one service.

Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within 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

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 101

TERMS AND CONDITIONS

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TERMS AND CONDITIONS

BILLING

assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice. There will be no adverse credit impact on the customer's payment and credit record, including credit scoring, both internally and externally, and the account will not be considered delinquent for any purpose if the Company receives the customer's payment within fifteen days after the date on which the Company issues the customer's bill.

Failure to receive a bill does not exempt Customer from these provisions of Company's Terms and Conditions.

READING OF SEPARATE METERS NOT COMBINED

For billing purposes, each meter upon Customer's premises will be considered separately and readings of two or more meters will not be combined except where Company's operating convenience requires the installation of two or more meters upon the customer's premises instead of one meter.

CUSTOMER RATE ASSIGNMENT

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.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

BILLING

assistance from an authorized agency will not be assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor will they be assessed or required to pay a late payment charge in any of the eleven (11) months following receipt of such pledge or notice. There will be no adverse credit impact on the customer's payment and credit record, including credit scoring, both internally and externally, and the account will not be considered delinquent for any purpose if the Company receives the customer's payment within fifteen days after the date on which the Company issues the customer's bill.

Failure to receive a bill does not exempt Customer from these provisions of Company's Terms and Conditions.

READING OF SEPARATE METERS NOT COMBINED

For billing purposes, each meter upon Customer's premises will be considered separately and readings of two (2) or more meters will not be combined except where Company's operating convenience requires the installation of two (2) or more meters upon Customer's premises instead of one (1) meter.

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.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 101.2
Canceling P.S.C. Electric No. 9, 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 then taking service under such a rate schedule, Company will not change Customer's rate assignment; it will remain Customer's responsibility to choose between optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1.

If Company determines during a review as described above that Customer is eligible to take service under more than one rate schedule and that Customer is not then taking service under such a rate schedule, Company will (1) provide reasonable notice to Customer of the options available and (2) assign Customer to the rate schedule Company reasonably believes will be most financially beneficial to Customer based on Customer's historical demand and usage, which assignment Company will change upon Customer's request to take service under another rate schedule for which Customer is eligible. Company shall have no refund obligation or bear any other liability or responsibility for its initial assignment of Customer to a rate for which Customer is eligible; it is at all times Customer's responsibility to choose between optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1.

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."

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 then taking service under such a rate schedule, Company will not change Customer's rate assignment; it will remain Customer's responsibility to choose between optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1.

If Company determines during a review as described above that Customer is eligible to take service under more than one rate schedule and that Customer is not then taking service under such a rate schedule, Company will (1) provide reasonable notice to Customer of the options available and (2) assign Customer to the rate schedule Company reasonably believes will be most financially beneficial to Customer based on Customer's historical demand and usage, which assignment Company will change upon Customer's request to take service under another rate schedule for which Customer is eligible. Company shall have no refund obligation or bear any other liability or responsibility for its initial assignment of Customer to a rate for which Customer is eligible; it is at all times Customer's responsibility to choose between optional rates, as stated in the Optional Rates section of Customer Responsibilities at Original Sheet Nos. 97 and 97.1.

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."

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Second Revision of Original Sheet No. 101.3
Canceling P.S.C. Electric No. 9, First Revision of 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 the customer's meter reading and billing records, Company may contact Customer to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether 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 Demand Charge shall be due regardless of any event or occurrence that might limit (a) Customer’s ability or interest in operating Customer’s facility, including but without limitation any acts of God, fires, floods, earthquakes, acts of government, terrorism, severe weather, riot, embargo, changes in law, or strikes or (b) Company’s ability to serve customer.

DATE OF ISSUE: April 22, 2013

DATE EFFECTIVE: January 4, 2013

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 the customer's meter reading and billing records, Company may contact Customer to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether 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 Demand Charge shall be due regardless of any event or occurrence that might limit (a) Customer’s ability or interest in operating Customer’s facility, including but without limitation any acts of God, fires, floods, earthquakes, acts of government, terrorism, severe weather, riot, embargo, changes in law, or strikes or (b) Company’s ability to serve customer.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 4, 2013

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 102
Canceling P.S.C. Electric No. 9, Original Sheet No. 102

TERMS AND CONDITIONS

DEPOSITS

GENERAL

1) Company may require a cash deposit or other guaranty from customers to secure payment of bills in accordance with 807 KAR 5:006, Section 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 four (4) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.

RESIDENTIAL

1) Residential customers are those customers served under Residential Service, Sheet No. 5.
2) The deposit for a residential customer is in the amount of $135.00, which is calculated in accordance with 807 KAR5:006, Section 8(1)(d)(2). For combination gas and electric customers, the total deposit will be $230.00.
3) Company shall retain Customer's deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.
4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 four (4) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.

RESIDENTIAL

1) Residential customers are those customers served under Residential Service Rate RS - T
Sheet No. 5, Residential Time-of-Day Energy Service Rate RTOD-Energy – Sheet No. 6, and T
Residential Time-of-Day Demand Service Rate RTOD-Demand – Sheet No. 7. T
2) The deposit for a residential customer is in the amount of $160.00, which is calculated in I
accordance with 807 KAR5:006, Section 8(1)(d)(2). For combination gas and electric
customers, the total deposit will be $260.00. I
3) Company shall retain Customer's deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.
4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated, at Customer's request, and based on Customer's actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.

T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 102.1
Canceling P.S.C. Electric No. 9, Original Sheet No. 102.1

TERMS AND CONDITIONS

Deposits

GENERAL SERVICE

1) General service customers are those customers served under General Service, Sheet No. 10.
2) The deposit for a general service customer is in the amount of $220.00, which is calculated in accordance with 807 KAR5:006, Section 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 energy usage is no more than 300 kWh per month.
2) Company shall retain Customer’s deposit as long as Customer remains on service.
3) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer’s request, and based on Customer’s actual usage. If the deposit on account differs from the recalculated amount by more than ten percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential or general service, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 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 percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 102.1

TERMS AND CONDITIONS

DEPOSITS

RESIDENTIAL (Continued) T

5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a T
new or greater credit risk, as determined by Company in its sole discretion, Company may T
require a new or additional deposit from Customer. T

GENERAL SERVICE

1) General service customers are those customers served under General Service Rate GS, T
Sheet No. 10.
2) The deposit for a general service customer is in the amount of $240.00, which is calculated in I
accordance with 807 KAR5:006, 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 energy 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 percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential or general service, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 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 percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 103

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to any residential customer or general service customer. Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in the plan at any time.

The budgeted amount will be determined by Company, and will be based on one-twelfth of Customer's usage for either an actual or estimated twelve (12) months. The budgeted amount will be subject to review and adjustment by Company at any time during Customer's budget year. If actual usage indicates Customer's account will not be current with the final payment in Customer's budget year, Customer will be required to pay their Budget Payment Plan account to $0 prior to the beginning of Customer's next budget year.

If Customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove Customer from the plan, restore the Customer to regular billing and require immediate payment of any deficiency. A customer removed from the Budget Payment Plan for non-payment may be prohibited from further participation in the plan for twelve (12) months.

Failure to receive a bill in no way exempts Customer from the provisions of these terms and conditions.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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. T

Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in the plan at any time.

The budgeted amount will be determined by Company, and will be based on one-twelfth of Customer's usage for either an actual or estimated twelve (12) months. The budgeted amount will be subject to review and adjustment by Company at any time during Customer's budget year. If actual usage indicates Customer's account will not be current with the final payment in Customer's budget year, Customer will be required to pay their Budget Payment Plan account to $0 prior to the beginning of Customer's next budget year.

If Customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove Customer from the plan, restore the Customer to regular billing and require immediate payment of any deficiency. A customer removed from the Budget Payment Plan for non-payment may be prohibited from further participation in the plan for twelve (12) months.

Failure to receive a bill in no way exempts Customer from the provisions of these terms and conditions.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

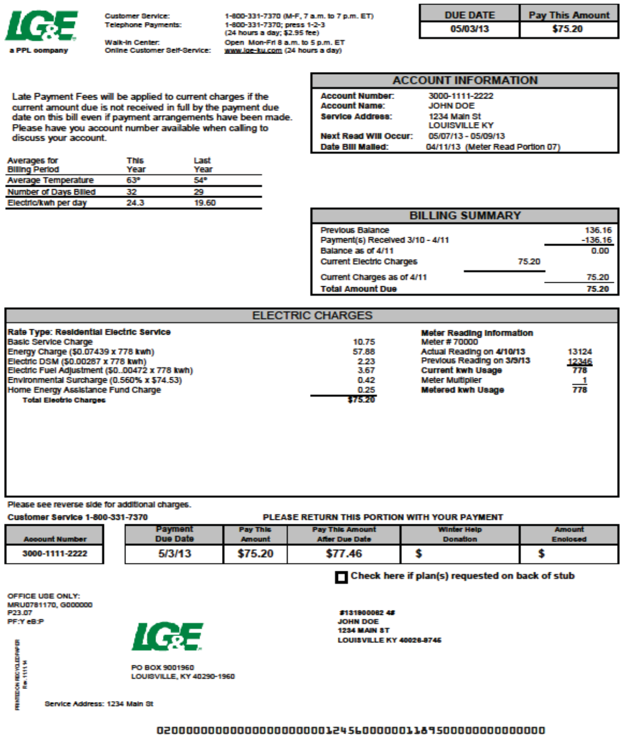
ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 104

TERMS AND CONDITIONS

Bill Format



a PPL company

Customer Service: 1-800-331-7370 (M-F, 7 a.m. to 7 p.m. ET)
Telephone Payments: 1-800-331-7370; press 1-2-3
(24 hours a day; $2.95 fee)
Walk-in Center: Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service: www.lge-ku.com (24 hours a day)

DUE DATE	Pay This Amount
05/03/13	$75.20

Late Payment Fees will be applied to current charges if the current amount due is not received in full by the payment due date on this bill even if payment arrangements have been made. Please have you account number available when calling to discuss your account.

ACCOUNT INFORMATION

Account Number: 3000-1111-2222
Account Name: JOHN DOE
Service Address: 1234 Main St
LOUISVILLE KY
Next Read Will Occur: 05/07/13 - 05/09/13
Date Bill Mailed: 04/11/13 (Meter Read Portion 07)

Averages for Billing Period	This Year	Last Year
Average Temperature	63°	54°
Number of Days Billed	32	29
Electric/kwh per day	24.3	19.60

BILLING SUMMARY

Previous Balance		136.16
Payment(s) Received 3/10 - 4/11		-136.16
Balance as of 4/11		0.00
Current Electric Charges	75.20	
Current Charges as of 4/11		75.20
Total Amount Due		**75.20**

ELECTRIC CHARGES

Rate Type: Residential Electric Service		**Meter Reading Information**	
Basic Service Charge	10.75	Meter # 70000	
Energy Charge ($0.07439 x 778 kwh)	57.88	Actual Reading on **4/10/13**	13124
Electric DSM ($0.00287 x 778 kwh)	2.23	Previous Reading on **3/9/13**	12346
Electric Fuel Adjustment ($0..00472 x 778 kwh)	3.67	**Current kwh Usage**	778
Environmental Surcharge (0.560% x $74.53)	0.42	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.25	**Metered kwh Usage**	778
Total Electric Charges	**$75.20**		

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number	Payment Due Date	Pay This Amount	Pay This Amount After Due Date	Winter Help Donation	Amount Enclosed
3000-1111-2222	5/3/13	$75.20	$77.46	$	$

☐ **Check here if plan(s) requested on back of stub**

OFFICE USE ONLY:
MRU0781170, G000000
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PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900082 4#
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40028-8745

PRINTED ON RECYCLED PAPER

Service Address: 1234 Main St

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DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: */s/* Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 104

TERMS AND CONDITIONS

Bill Format

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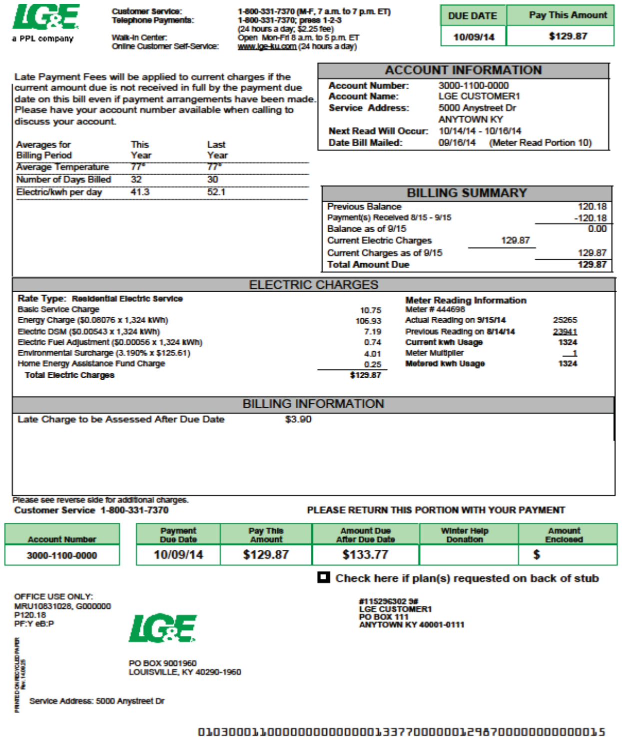

a PPL company

Customer Service: 1-800-331-7370 (M-F, 7 a.m. to 7 p.m. ET)
Telephone Payments: 1-800-331-7370; press 1-2-3
(24 hours a day; $2.25 fee)
Walk-In Center: Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service: www.lge-ku.com (24 hours a day)

DUE DATE	Pay This Amount
10/09/14	$129.87

Late Payment Fees will be applied to current charges if the current amount due is not received in full by the payment due date on this bill even if payment arrangements have been made. Please have your account number available when calling to discuss your account.

ACCOUNT INFORMATION

Account Number: 3000-1100-0000
Account Name: LGE CUSTOMER1
Service Address: 5000 Anystreet Dr
ANYTOWN KY
Next Read Will Occur: 10/14/14 - 10/16/14
Date Bill Mailed: 09/16/14 (Meter Read Portion 10)

Averages for Billing Period	This Year	Last Year
Average Temperature	77°	77°
Number of Days Billed	32	30
Electric/kwh per day	41.3	52.1

BILLING SUMMARY

Previous Balance		120.18
Payment(s) Received 8/15 - 9/15		-120.18
Balance as of 9/15		0.00
Current Electric Charges	129.87	
Current Charges as of 9/15		129.87
Total Amount Due		**129.87**

ELECTRIC CHARGES

Rate Type: **Residential Electric Service**		**Meter Reading Information**	
Basic Service Charge	10.75	Meter # 444698	
Energy Charge ($0.08076 x 1,324 kWh)	106.93	Actual Reading on **9/15/14**	25265
Electric DSM ($0.00543 x 1,324 kWh)	7.19	Previous Reading on **8/14/14**	23941
Electric Fuel Adjustment ($0.00056 x 1,324 kWh)	0.74	**Current kwh Usage**	1324
Environmental Surcharge (3.190% x $125.61)	4.01	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.25	**Metered kwh Usage**	1324
Total Electric Charges	**$129.87**		

BILLING INFORMATION

Late Charge to be Assessed After Due Date $3.90

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number	Payment Due Date	Pay This Amount	Amount Due After Due Date	Winter Help Donation	Amount Enclosed
3000-1100-0000	10/09/14	$129.87	$133.77		$

☐ **Check here if plan(s) requested on back of stub**

OFFICE USE ONLY:
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PO BOX 9001960
LOUISVILLE, KY 40290-1960

#115296302 9#
LGE CUSTOMER1
PO BOX 111
ANYTOWN KY 40001-0111

PRINTED ON RECYCLED PAPER

Service Address: 5000 Anystreet Dr

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

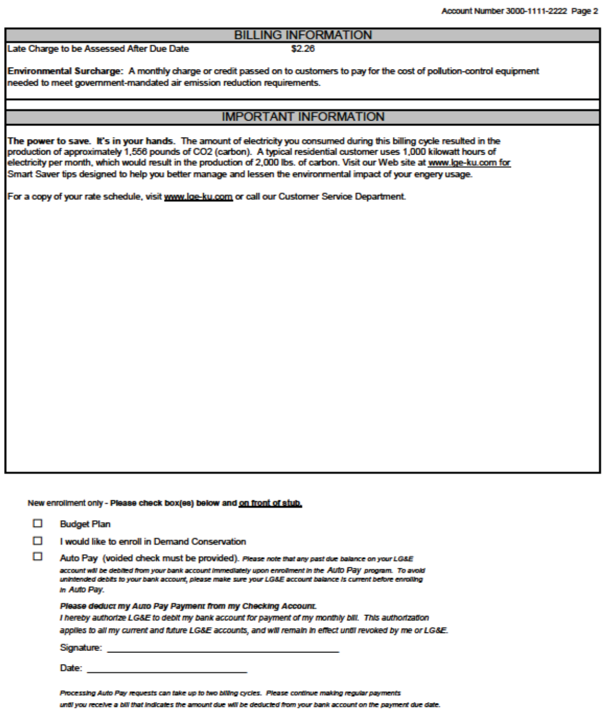
ISSUED BY: */s/* Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 104.1

TERMS AND CONDITIONS

Bill Format



Account Number 3000-1111-2222 Page 2

BILLING INFORMATION

Late Charge to be Assessed After Due Date $2.26

Environmental Surcharge: A monthly charge or credit passed on to customers to pay for the cost of pollution-control equipment needed to meet government-mandated air emission reduction requirements.

IMPORTANT INFORMATION

The power to save. It's in your hands. The amount of electricity you consumed during this billing cycle resulted in the production of approximately 1,556 pounds of CO2 (carbon). A typical residential customer uses 1,000 kilowatt hours of electricity per month, which would result in the production of 2,000 lbs. of carbon. Visit our Web site at www.lge-ku.com for Smart Saver tips designed to help you better manage and lessen the environmental impact of your engery usage.

For a copy of your rate schedule, visit www.lge-ku.com or call our Customer Service Department.

New enrollment only - **Please check box(es) below and on front of stub.**

☐ Budget Plan

☐ I would like to enroll in Demand Conservation

☐ Auto Pay (voided check must be provided). *Please note that any past due balance on your LG&E account will be debited from your bank account immediately upon enrollment in the Auto Pay program. To avoid unintended debits to your bank account, please make sure your LG&E account balance is current before enrolling in Auto Pay.*

Please deduct my Auto Pay Payment from my Checking Account.
I hereby authorize LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

Signature: ______________________________

Date: ______________________

Processing Auto Pay requests can take up to two billing cycles. Please continue making regular payments until you receive a bill that indicates the amount due will be deducted from your bank account on the payment due date.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 104.1

TERMS AND CONDITIONS

Bill Format

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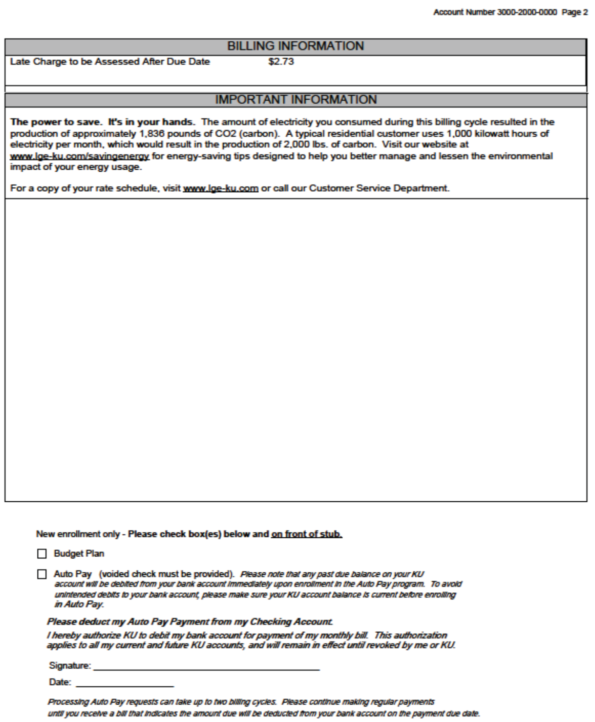


Account Number 3000-2000-0000 Page 2

BILLING INFORMATION

Late Charge to be Assessed After Due Date $2.73

IMPORTANT INFORMATION

The power to save. It's in your hands. The amount of electricity you consumed during this billing cycle resulted in the production of approximately 1,836 pounds of CO2 (carbon). A typical residential customer uses 1,000 kilowatt hours of electricity per month, which would result in the production of 2,000 lbs. of carbon. Visit our website at www.lge-ku.com/savingenergy for energy-saving tips designed to help you better manage and lessen the environmental impact of your energy usage.

For a copy of your rate schedule, visit www.lge-ku.com or call our Customer Service Department.

New enrollment only - **Please check box(es) below and on front of stub.**

☐ Budget Plan

☐ Auto Pay (voided check must be provided). *Please note that any past due balance on your KU account will be debited from your bank account immediately upon enrollment in the Auto Pay program. To avoid unintended debits to your bank account, please make sure your KU account balance is current before enrolling in Auto Pay.*

Please deduct my Auto Pay Payment from my Checking Account.
I hereby authorize KU to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future KU accounts, and will remain in effect until revoked by me or KU.

Signature: ______________________________

Date: ______________________

Processing Auto Pay requests can take up to two billing cycles. Please continue making regular payments until you receive a bill that indicates the amount due will be deducted from your bank account on the payment due date.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

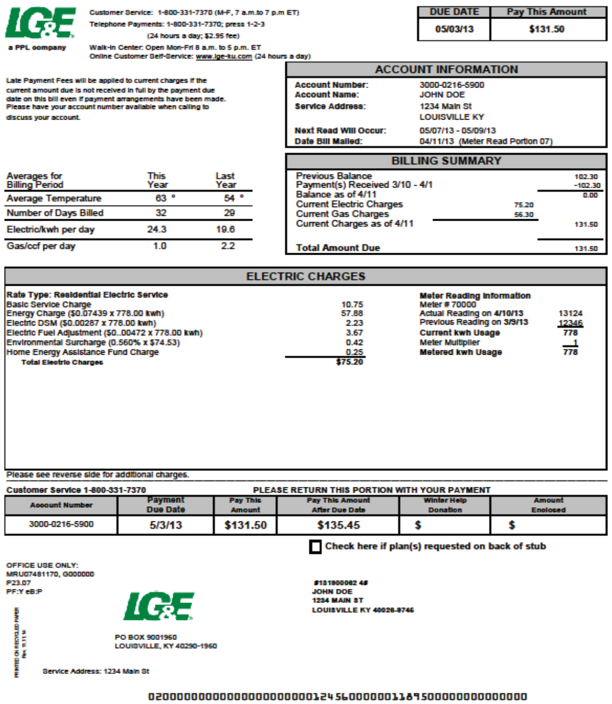
ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 104.2

TERMS AND CONDITIONS

Bill Format



LG&E
a PPL company

Customer Service: 1-800-331-7370 (M-F, 7 a.m.to 7 p.m ET)
Telephone Payments: 1-800-331-7370; press 1-2-3
(24 hours a day; $2.95 fee)
Walk-In Center: Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service: www.lge-ku.com (24 hours a day)

DUE DATE	Pay This Amount
05/03/13	$131.50

Late Payment Fees will be applied to current charges if the current amount due is not received in full by the payment due date on this bill even if payment arrangements have been made. Please have your account number available when calling to discuss your account.

ACCOUNT INFORMATION

Account Number:	3000-0216-5900
Account Name:	JOHN DOE
Service Address:	1234 Main St LOUISVILLE KY
Next Read Will Occur:	05/07/13 - 05/09/13
Date Bill Mailed:	04/11/13 (Meter Read Portion 07)

Averages for Billing Period	This Year	Last Year
Average Temperature	63 °	54 °
Number of Days Billed	32	29
Electric/kwh per day	24.3	19.6
Gas/ccf per day	1.0	2.2

BILLING SUMMARY

Previous Balance		102.30
Payment(s) Received 3/10 - 4/1		-102.30
Balance as of 4/11		0.00
Current Electric Charges	75.20	
Current Gas Charges	56.30	
Current Charges as of 4/11		131.50
Total Amount Due		131.50

ELECTRIC CHARGES

Rate Type: Residential Electric Service		**Meter Reading Information**	
Basic Service Charge	10.75	Meter # 70000	
Energy Charge ($0.07439 x 778.00 kwh)	57.88	Actual Reading on **4/10/13**	13124
Electric DSM ($0.00287 x 778.00 kwh)	2.23	Previous Reading on **3/9/13**	12346
Electric Fuel Adjustment ($0..00472 x 778.00 kwh)	3.67	**Current kwh Usage**	778
Environmental Surcharge (0.560% x $74.53)	0.42	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.25	**Metered kwh Usage**	778
Total Electric Charges	$75.20		

Please see reverse side for additional charges.

Customer Service 1-800-331-7370 **PLEASE RETURN THIS PORTION WITH YOUR PAYMENT**

Account Number	Payment Due Date	Pay This Amount	Pay This Amount After Due Date	Winter Help Donation	Amount Enclosed
3000-0216-5900	5/3/13	$131.50	$135.45	$	$

☐ **Check here if plan(s) requested on back of stub**

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LG&E
PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900062 4#
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40026-9745

Service Address: 1234 Main St

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DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: */s/* Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 104.2

TERMS AND CONDITIONS

Bill Format

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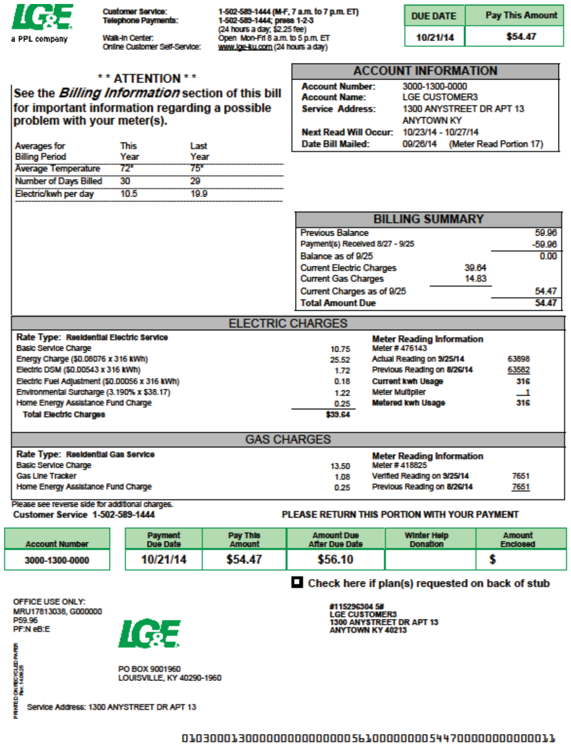

LG&E
a PPL company

Customer Service:	**1-502-589-1444 (M-F, 7 a.m. to 7 p.m. ET)**
Telephone Payments:	**1-502-589-1444; press 1-2-3** (24 hours a day; $2.25 fee)
Walk-In Center:	Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service:	www.lge-ku.com (24 hours a day)

DUE DATE	Pay This Amount
10/21/14	$54.47

*** * ATTENTION * ***

See the *Billing Information* section of this bill for important information regarding a possible problem with your meter(s).

Averages for Billing Period	This Year	Last Year
Average Temperature	72°	75°
Number of Days Billed	30	29
Electric/kwh per day	10.5	19.9

ACCOUNT INFORMATION

Account Number:	3000-1300-0000
Account Name:	LGE CUSTOMER3
Service Address:	1300 ANYSTREET DR APT 13 ANYTOWN KY
Next Read Will Occur:	10/23/14 - 10/27/14
Date Bill Mailed:	09/26/14 (Meter Read Portion 17)

BILLING SUMMARY

Previous Balance		59.96
Payment(s) Received 8/27 - 9/25		-59.96
Balance as of 9/25		0.00
Current Electric Charges	39.64	
Current Gas Charges	14.83	
Current Charges as of 9/25		54.47
Total Amount Due		54.47

ELECTRIC CHARGES

Rate Type: Residential Electric Service		**Meter Reading Information**	
Basic Service Charge	10.75	Meter # 476143	
Energy Charge ($0.08076 x 316 kWh)	25.52	Actual Reading on **9/25/14**	63898
Electric DSM ($0.00543 x 316 kWh)	1.72	Previous Reading on **8/26/14**	63582
Electric Fuel Adjustment ($0.00056 x 316 kWh)	0.18	**Current kwh Usage**	316
Environmental Surcharge (3.190% x $38.17)	1.22	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.25	**Metered kwh Usage**	316
Total Electric Charges	$39.64		

GAS CHARGES

Rate Type: Residential Gas Service		**Meter Reading Information**	
Basic Service Charge	13.50	Meter # 418825	
Gas Line Tracker	1.08	Verified Reading on **9/25/14**	7651
Home Energy Assistance Fund Charge	0.25	Previous Reading on **8/26/14**	7651

Please see reverse side for additional charges.

Customer Service 1-502-589-1444 **PLEASE RETURN THIS PORTION WITH YOUR PAYMENT**

Account Number	Payment Due Date	Pay This Amount	Amount Due After Due Date	Winter Help Donation	Amount Enclosed
3000-1300-0000	10/21/14	$54.47	$56.10		$

☐ **Check here if plan(s) requested on back of stub**

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Rev. 140825

LG&E
PO BOX 9001960
LOUISVILLE, KY 40290-1960

#115296304 5#
LGE CUSTOMER3
1300 ANYSTREET DR APT 13
ANYTOWN KY 40213

Service Address: 1300 ANYSTREET DR APT 13

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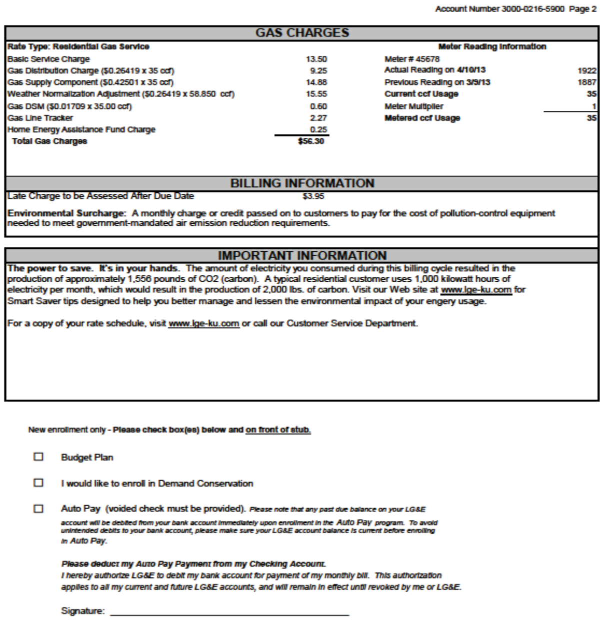
DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: */s/* Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format



Account Number 3000-0216-5900 Page 2

GAS CHARGES

Rate Type: Residential Gas Service		**Meter Reading Information**	
Basic Service Charge	13.50	Meter # 45678	
Gas Distribution Charge ($0.26419 x 35 ccf)	9.25	Actual Reading on **4/10/13**	1922
Gas Supply Component ($0.42501 x 35 ccf)	14.88	Previous Reading on **3/9/13**	1887
Weather Normalization Adjustment ($0.26419 x 58.850 ccf)	15.55	**Current ccf Usage**	35
Gas DSM ($0.01709 x 35.00 ccf)	0.60	Meter Multiplier	1
Gas Line Tracker	2.27	**Metered ccf Usage**	35
Home Energy Assistance Fund Charge	0.25		
Total Gas Charges	**$56.30**		

BILLING INFORMATION

Late Charge to be Assessed After Due Date $3.95

Environmental Surcharge: A monthly charge or credit passed on to customers to pay for the cost of pollution-control equipment needed to meet government-mandated air emission reduction requirements.

IMPORTANT INFORMATION

The power to save. It's in your hands. The amount of electricity you consumed during this billing cycle resulted in the production of approximately 1,556 pounds of CO2 (carbon). A typical residential customer uses 1,000 kilowatt hours of electricity per month, which would result in the production of 2,000 lbs. of carbon. Visit our Web site at www.lge-ku.com for Smart Saver tips designed to help you better manage and lessen the environmental impact of your engery usage.

For a copy of your rate schedule, visit www.lge-ku.com or call our Customer Service Department.

New enrollment only - **Please check box(es) below and on front of stub.**

☐ Budget Plan

☐ I would like to enroll in Demand Conservation

☐ Auto Pay (voided check must be provided). *Please note that any past due balance on your LG&E account will be debited from your bank account immediately upon enrollment in the Auto Pay program. To avoid unintended debits to your bank account, please make sure your LG&E account balance is current before enrolling in Auto Pay.*

Please deduct my Auto Pay Payment from my Checking Account.
I hereby authorize LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

Signature: ________________________________

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: */s/* Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

TERMS AND CONDITIONS

Bill Format

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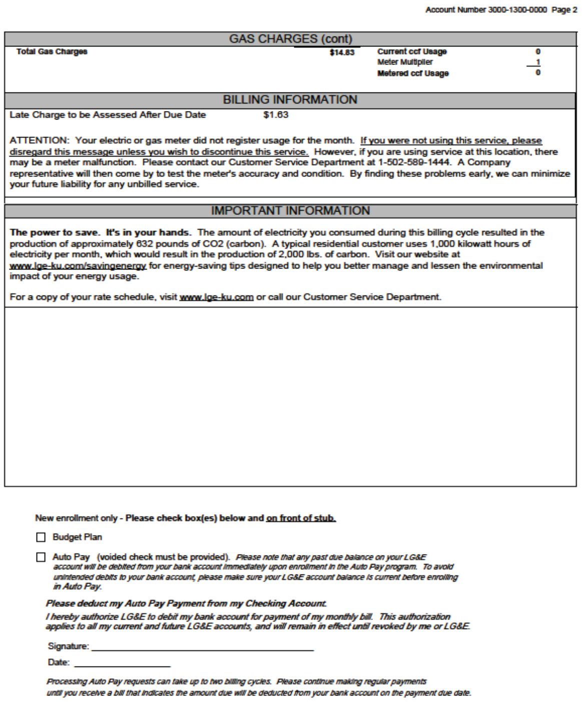

Account Number 3000-1300-0000 Page 2

GAS CHARGES (cont)

Total Gas Charges	**$14.83**	**Current ccf Usage**	0
		Meter Multiplier	1
		Metered ccf Usage	0

BILLING INFORMATION

Late Charge to be Assessed After Due Date $1.63

ATTENTION: Your electric or gas meter did not register usage for the month. If you were not using this service, please disregard this message unless you wish to discontinue this service. However, if you are using service at this location, there may be a meter malfunction. Please contact our Customer Service Department at 1-502-589-1444. A Company representative will then come by to test the meter's accuracy and condition. By finding these problems early, we can minimize your future liability for any unbilled service.

IMPORTANT INFORMATION

The power to save. It's in your hands. The amount of electricity you consumed during this billing cycle resulted in the production of approximately 632 pounds of CO2 (carbon). A typical residential customer uses 1,000 kilowatt hours of electricity per month, which would result in the production of 2,000 lbs. of carbon. Visit our website at www.lge-ku.com/savingenergy for energy-saving tips designed to help you better manage and lessen the environmental impact of your energy usage.

For a copy of your rate schedule, visit www.lge-ku.com or call our Customer Service Department.

New enrollment only - **Please check box(es) below and on front of stub.**

☐ Budget Plan

☐ Auto Pay (voided check must be provided). *Please note that any past due balance on your LG&E account will be debited from your bank account immediately upon enrollment in the Auto Pay program. To avoid unintended debits to your bank account, please make sure your LG&E account balance is current before enrolling in Auto Pay.*

Please deduct my Auto Pay Payment from my Checking Account.
I hereby authorize LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

Signature: ________________________________

Date: ________________

Processing Auto Pay requests can take up to two billing cycles. Please continue making regular payments until you receive a bill that indicates the amount due will be deducted from your bank account on the payment due date.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: */s/* Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 105
Canceling P.S.C. Electric No. 9, Original Sheet No. 105

TERMS AND CONDITIONS

Discontinuance of Service

In accordance with and subject to the rules and regulations of the Public Service Commission of Kentucky, Company shall have the right to refuse or discontinue service to an applicant or customer under the following conditions:

A. When Company's or Commission's rules and regulations have not been complied with. However, service may be discontinued or refused only after Company has made a reasonable effort to induce Customer to comply with its rules and then only after Customer has been given at least ten (10) days written notice of such intention, mailed to his last known address.

B. When a dangerous condition is found to exist on the customer's or applicant's premises. In such case service will be discontinued without notice or refused, as the case might be. Company will notify the customer or applicant immediately of the reason for the discontinuance or refusal and the corrective action to be taken before service can be restored or initiated.

C. When a customer or applicant refuses or neglects to provide reasonable access and/or easements to and on his premises for the purposes of installation, operation, meter reading, maintenance, or removal of Company's property. Customer shall be given fifteen (15) days written notice of Company's intention to discontinue or refuse service.

D. When Applicant is indebted to Company for service furnished. Company may refuse to serve until indebtedness is paid.

E. When customer or applicant does not comply with state, municipal or other codes, rules and regulations applying to such service.

F. When directed to do so by governmental authority.

G. Service will not be supplied to any premises if the applicant or customer is indebted to Company for service previously supplied at the same or any other premises until payment of such indebtedness shall have been made. Service will not be continued to any premises if the applicant or customer is indebted to Company for service previously supplied at the same premises in accordance with 807 KAR 5:006, Section 15(1)(f). Unpaid balances of previously rendered Final Bills may be transferred to any account for which the customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred final bills will be subject to Company's collections and disconnect procedures in accordance with 807 KAR 5:006, Section 15(1)(f). Final Bills transferred following a lapse in service will not be subject to disconnection unless: (1) such service was provided pursuant to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 T
limited to, electronic mail, to Customer's last known address. T

B. When a dangerous condition is found to exist on the customer's or applicant's premises. In such case service will be discontinued without notice or refused, as the case might be. Company will notify the customer or applicant immediately of the reason for the discontinuance or refusal and the corrective action to be taken before service can be restored or initiated.

C. When Customer or Applicant refuses or neglects to provide reasonable access and/or easements T
to and on Customer's or Applicant's premises for the purposes of installation, operation, meter T
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 T
mail), of Company's intention to discontinue or refuse service. T

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 T
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 T
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 T
Customer is indebted to Company for service previously supplied at the same premises in T
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 T
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
T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 105.1
Canceling P.S.C. Electric No. 9, Original Sheet No. 105.1

TERMS AND CONDITIONS

Discontinuance of Service

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 the applicant is merely acting as an agent of a person or former customer who is indebted to Company for service previously supplied at the same or other premises until payment of such indebtedness shall have been made. Service will not be supplied where the applicant is a partnership or corporation whose general partner or controlling stockholder is a present or former customer who is indebted to Company for service previously supplied at the same premises until payment of such indebtedness shall have been made.

H. For non-payment of bills. Company shall have the right to discontinue service for non-payment of bills after Customer has been given at least ten days written notice separate from his original bill. Cut-off may be effected not less than twenty-seven (27) days after the mailing date of original bills unless, prior to discontinuance, a residential customer presents to Company a written certificate, signed by a physician, registered nurse, or public health officer, that such discontinuance will aggravate an existing illness or infirmity on the affected premises, in which case discontinuance may be effected not less than thirty (30) days from the original date of discontinuance. Company shall notify the customer, in writing, of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance.

I. For fraudulent or illegal use of service. When Company discovers evidence that by fraudulent or illegal means a customer has obtained unauthorized service or has diverted the service for unauthorized use or has obtained service without same being properly measured, the service to the customer may be discontinued without notice. Within twenty-four (24) hours after such termination, Company shall send written notification to Customer of the reasons for such discontinuance of service and of Customer's right to challenge the termination by filing a formal complaint with the Public Service Commission of Kentucky. Company's right of termination is separate from and in addition to any other legal remedies which the utility may pursue for illegal use or theft of service. Company shall not be required to restore service until Customer has complied with all rules of Company and regulations of the Commission and Company has been reimbursed for the estimated amount of the service rendered and the cost to Company incurred by reason of the fraudulent use.

When service has been discontinued for any of the above reasons, Company shall not be responsible for any damage that may result therefrom.

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DATE EFFECTIVE: February 6, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 105.1

TERMS AND CONDITIONS

Discontinuance of Service

15(1)(f). Final Bills transferred following a lapse in service will not be subject to disconnection T
unless: (1) such service was provided pursuant to a fraudulent application submitted by T
Customer; (2) Customer and Company have entered into a contractual agreement T
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 T
Company for service previously supplied at the same or other premises until payment of such
indebtedness shall have been made. Service will not be supplied where the Applicant is a T
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 T
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 T
delivered, including, but not limited to, electronic mail), of state and federal programs which T
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 T
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 T
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

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Original Sheet No. 105.2

TERMS AND CONDITIONS

Discontinuance of Service

Discontinuance or refusal of service shall be in addition to, and not in lieu of, any other rights or remedies available to Company.

Company may defer written notice based on Customer's payment history provided Company continues to provide the required ten (10) days written notice prior to discontinuance of service.

DATE OF ISSUE: January 31, 2013

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ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 105.2

TERMS AND CONDITIONS

Discontinuance of Service

use or theft of service. Company shall not be required to restore service until Customer has complied with all rules of Company and regulations of the Commission and Company has been reimbursed for the estimated amount of the service rendered and the cost to Company incurred by reason of the fraudulent use. 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. T T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 106
Canceling P.S. C. Electric No. 9, 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 Louisville Gas and Electric Company.
2) "Customer" shall mean the applicant for service. When more than one electric service is requested by an applicant on the same extension, such request shall be considered one customer under this plan when the additional service request(s) is only for incidental or minor convenience loads or when the applicant for service is the developer of a subdivision.
3) "Line Extension" shall mean the single phase facilities required to serve Customer by the shortest route most convenient to Company from the nearest existing adequate Company facilities to Customer's delivery point, approved by Company, and excluding transformers, service drop, and meters, if required and normally provided to like customers.
4) "Permanent Service" shall mean service contracted for under the terms of the applicable rate schedule but not less than one year and where the intended use is not seasonal, intermittent, or speculative in nature.
5) "Commission" shall mean the Public Service Commission of Kentucky.

C. GENERAL

1) All extensions of service will be made through the use of overhead facilities except as provided in these rules.
2) Customer requesting service which requires an extension(s) shall furnish to Company, at no cost, properly executed easement(s) for right-of-way across Customer's property to be served.
3) Customer requesting extension of service into a subdivision, subject to the jurisdiction of a public commission, board, committee, or other agency with authority to zone or otherwise regulate land use in the area and require a plat (or Plan) of the subdivision, Customer shall furnish, at no cost, Company with the plat (or plan) showing street and lot locations with utility easement and required restrictions. Plats (or plans) supplied shall have received final approval of the regulating body and recorded in the office of the appropriate County Court Clerk when required. Should no regulating body exist for the area into which service is to be extended, Customer shall furnish Company the required easement.
4) The title to all extensions, rights-of way, permits, and easements shall be and remain with Company.
5) Where Company is required or elects to construct an additional extension or lateral to serve Customer or another customer, Company reserves the right to connect to any extension constructed under this plan and Customer shall grant to Company, at no cost, properly executed easement(s) for right-of-way across Customer's property for the additional extension or lateral.

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 Louisville Gas and Electric Company.
2) "Customer" shall mean the applicant for service. When more than one electric service is requested by an applicant on the same extension, such request shall be considered one customer under this plan when the additional service request(s) is only for incidental or minor convenience loads or when the applicant for service is the developer of a subdivision.
3) "Line Extension" shall mean the single phase facilities required to serve Customer by the shortest route most convenient to Company from the nearest existing adequate Company facilities to Customer's delivery point, approved by Company, and excluding transformers, service drop, and meters, if required and normally provided to like customers.
4) "Permanent Service" shall mean service contracted for under the terms of the applicable rate schedule but not less than one year and where the intended use is not seasonal, intermittent, or speculative in nature.
5) "Commission" shall mean the Public Service Commission of Kentucky.

C. GENERAL

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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. T

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DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 106.1
Canceling P.S.C. Electric No. 9, Original Sheet No. 106.1

TERMS AND CONDITIONS

Line Extension Plan

C. GENERAL (continued)

6) Customer must agree in writing to take service when the extension is completed and have his building or other permanent facility wired and ready for connection.
7) Nothing herein shall be construed as preventing Company from making electric line extensions under more favorable terms than herein prescribed provided the potential revenue is of such amount and permanency as to warrant such terms and render economically feasible the capital expenditure involved and provided such extensions are made to other customers under similar conditions.
8) Company may require a non-refundable deposit in cases where Customer does not have a real need or in cases where the estimated revenue does not justify the investment.
9) The Company shall not be obligated to extend its lines in cases where such extensions, in the good judgment of Company, would be infeasible, impractical, or contrary to good engineering or operating practice, unless otherwise ordered by Commission.

D. NORMAL LINE EXTENSIONS

1) In accordance with 807 KAR 5:041, Section 11(1), Company will provide, at no cost, a line extension of up to 1,000 feet to Customer requesting permanent service where the installed transformer capacity does not exceed 25kVA.
2) Where Customer requires poly-phase service or transformer capacity in excess of 25kVA and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in NORMAL LINE EXTENSIONS ¶ 1 above.

E. OTHER LINE EXTENSIONS

1) In accordance with 807 KAR 5:041, Section 11(2), Company shall provide to Customer requesting permanent service a line extension in excess of 1,000 feet per customer but Company may require the total cost of the footage in excess of 1,000 feet per customer, based on the average cost per foot of the total extension, be deposited with Company by Customer.
2) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension for each additional customer connected during that year directly to the original extension for which the deposit was made.
3) Each year for ten (10) years Company shall refund to Customer, who made the deposit for excess footage, the cost of 1,000 feet of extension less the length of the lateral or extension for each additional customer connected during that year by a lateral or extension to the original extension for which the deposit was made.
4) No refund shall be made for additional customers connected to an extension or lateral from the original extension for which the deposit was made.
5) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten (10) year refund period ends.

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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. T
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.
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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. T

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 106.2
Canceling P. S. C. Electric No. 9, Original Sheet No. 106.2

TERMS AND CONDITIONS

Line Extension Plan

E. OTHER LINE EXTENSIONS (continued)

6) Where Customer requires poly-phase service or transformer capacity above 25kVA per customer and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in OTHER LINE EXTENSIONS ¶ 1 above.

F. OVERHEAD LINE EXTENSIONS FOR SUBDIVISIONS

1) In accordance with 807 KAR 5:041, Section 11(3), Customer desiring service extended for and through a subdivision may be required by Company to deposit the total cost of the extension.
2) Each year for ten (10) years Company shall refund to Customer, the cost of 1,000 feet of extension for each additional customer connected during that year directly to the original extension for which the deposit was made.
3) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten-year refund period ends.

G. MOBILE HOME LINE EXTENSIONS

1) Company will make line extensions for service to mobile homes in accordance with 807 KAR 5:041, Section 12, and Commission's Order, dated August 9, 1991, in Case No. 91-213,
2) Company shall provide, at no cost, a line extension of up to 300 feet to Customer requesting permanent service for a mobile home.
3) Company shall provide to Customer requesting permanent service for a mobile home a line extension in excess of 300 feet and up to 1,000 feet but Company may require the total cost of the footage in excess of 300 feet, based on the average cost per foot of the total extension, be deposited with Company by Customer. Beyond 1,000 feet the policies set forth in OTHER LINE EXTENSIONS shall apply.
4) Each year for four (4) years Company shall refund to Customer equal amounts of the deposit for the extension from 300 feet to 1,000 feet.
5) If service is disconnected for sixty (60) days, if the original mobile home is removed and not replaced by another mobile home or a permanent structure in sixty (60) days, the remainder of the deposit is forfeited.
6) No refund will be made except to the original customer.

H. UNDERGROUND LINE EXTENSIONS

General

1) Company will make underground line extensions for service to new residential customers and subdivisions in accordance with 807 KAR 5:041, Section 21.
2) In order that Company may make timely provision for materials, and supplies, Company may require Customer to execute a contract for an underground extension under these Terms and

DATE OF ISSUE: January 31, 2013

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
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Louisville Gas and Electric Company

P.S.C. Electric No. 10, 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 25kVA per customer and Company provides such facilities, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost to Company in providing facilities above that required in OTHER LINE EXTENSIONS ¶ 1 above. T

F. OVERHEAD LINE EXTENSIONS FOR SUBDIVISIONS

1) In accordance with 807 KAR 5:041, Section 11(3), Customer desiring service extended for and through a subdivision may be required by Company to deposit the total cost of the extension.
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2) 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.
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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS

General (continued

Conditions with Company at least six (6) months prior to the anticipated date service is needed and Company may require Customer to deposit with Company at least 10% of any amounts due under the contract at the time of execution. Customer shall deposit the balance of any amounts due under the contract with Company prior to ordering materials or commencement of actual construction by Company of facilities covered by the contract.

3) Customer shall give Company at least 120 days written notice prior to the anticipated date service is needed and Company will undertake to complete installation of its facilities at least thirty (30) days prior to that date. However, nothing herein shall be interpreted to require Company to extend service to portions of subdivisions not under active development.
4) At Company's discretion, Customer may perform a work contribution, to Company's specifications, including but not limited to conduit, setting pads, or any required trenching and backfilling, and Company shall credit amounts due from Customer for underground service by Company's estimated cost for such work contribution.
5) Customer will provide, own, operate and maintain all electric facilities on his side of the point of delivery including the service and with the exception of Company's meter.
6) The normal point of delivery shall be at a junction device at the corner of the lot nearest Company's facilities. Customer shall bring Customer's service line to a point within 1 1/2 feet of the junction device with a sufficient length of service conductor left coiled above grade for completion of installation and connection by Company
7) In consideration of Customer's underground service, Company shall credit any amounts due under the contract for each service at the rate of $50.00 or Company's average estimated installed cost for an overhead service whichever is greater.
8) Unit charges, where specified herein, are determined from Company's estimate of Company's average unit cost of such construction and the estimated cost differential between underground and overhead distribution systems in representative residential subdivisions.
9) Three phase primary required to supply either individual loads or the local distribution system may be overhead unless Customer chooses underground construction and deposits with Company a non-refundable deposit for the cost differential.

Individual Premises

1) Within the City of Louisville underground district or in those cases where Company's engineering or operating convenience requires the construction of an underground extension to an individual premise, the excess of the cost of an underground extension over that of an overhead extension will be at no cost.

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS

General (continued

2) In order that Company may make timely provision for materials, and supplies, Company may T require Customer to execute a contract for an underground extension under these Terms and T 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 T the point of delivery including the service and with the exception of Company's meter.
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8) Unit charges, where specified herein, are determined from Company's estimate of Company's average unit cost of such construction and the estimated cost differential between underground and overhead distribution systems in representative residential subdivisions.
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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 9, Second Revision of Original Sheet No. 106.4
Canceling P.S.C. Electric No. 9, First Revision of Original Sheet No. 106.4

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS
Individual Premises (continued)

2) In cases other than those specified in 1) above, where Customer requests and Company agrees to supply underground service to an individual premise, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.

Medium Density Subdivisions

1) A medium density residential subdivision is defined as containing ten or more lots for the construction of new residential buildings each designed for less than five (5)-family occupancy.
2) Customer shall provide any required trenching and backfilling or at Company's discretion be required to deposit with Company a non-refundable amount determined by a unit charge of $6.94 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.
3) The Customer may be required to advance to the Company the Company's full estimated cost of construction of an underground electric distribution extension. Where Customer is required to provide trenching and backfilling, advance will be the Company's full estimate cost of construction. Where Customer is required to deposit with the Company a non-refundable advance in place of trenching and backfilling, advance will be determined by a unit charge of $21.17 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.
4) Each year for ten (10) years Company shall refund to Customer an amount determined as follows:
    a. Where customer is required to provide trenching and backfilling, a refund of $5,000 for each customer connected during that year.
    b. Where customer is required to provide a non-refundable advance, 500 times the difference in the unit charge advance amount in 3) and the non-refundable unit charge advance in 2) for each customer connected during that year.
5) In no case shall the refunds provided for herein exceed the amounts deposited less any non-refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends.

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.

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 106.4

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS
Individual Premises (continued)

2) In cases other than those specified in 1) above, where Customer requests and Company agrees to supply underground service to an individual premise, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.

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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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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 $21.17 per aggregate lot front-foot along all streets contiguous to the lots to be served through an underground extension.
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    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.

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DATE EFFECTIVE: December 31, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Line Extension Plan

H. UNDERGROUND EXTENSIONS

High Density Subdivisions (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 for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.
3) The Customer may be required to advance to the Company the Company's full estimated cost of construction of an underground electric distribution extension.
   i. Company shall refund to Customer any amounts due when permanent service is provided by Company to twenty (20%) percent of the family units in Customer's project.
   ii. In no case shall the refunds provided for herein exceed the amounts deposited less any non-refundable charges applicable to the project nor shall any refund be made after a ten-year refund period ends.

Other Underground Subdivisions

In cases where a particular residential subdivision does not meet the conditions provided for above, Customer requests and Company agrees to supply underground service, Company may require Customer to pay, in advance, a non-refundable amount for the additional cost of the underground extension (including all associated facilities) over the cost of an overhead extension of equivalent capacity.

I. SPECIAL CASES

1) Where Customer requests service that is seasonal, intermittent, speculative in nature, at voltages of 34.5kV or greater, or where the facilities requested by Customer do not meet the Terms and Conditions outlines in previous sections of LINE EXTENSION PLAN and the anticipated revenues do not justify the Company's installing facilities required to meet Customer's needs, Company may request that Customer deposit with Company a refundable amount to justify Company's investment.
2) Each year for ten (10) years, Company shall refund to Customer, an amount calculated by:
   a. Adding the sum of Customer's annual base rate monthly electric demand billing for that year to the sum of the annual base rate monthly electric demand billing of the monthly electric billing for that year of any customer(s), who connects directly to the facilities provided for in this agreement and requiring no further investment by Company
   b. times the refundable amount divided by the estimated total ten-year base rate electric demand billing required to justify the investment.
3) The total amount refunded shall not exceed the amount originally deposited nor shall any refund be made after the ten-year refund period ends.

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State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

Line Extension Plan

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 107
Canceling P.S.C. Electric No. 9, Original Sheet No. 107

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PURPOSE

To provide procedures for reducing the consumption of electric energy on the Louisville Gas and Electric Company ("Company") system in the event of a capacity shortage and to restore service following an outage. Notwithstanding any provisions of these Energy Curtailment and Service Restoration Procedures, Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that Company believes necessary, in whatever order consistent with good utility practices and not on an unduly discriminatory basis, to preserve system integrity and to prevent the collapse of Company's electric system or interconnected electric network or to restore service following an outage. Such actions will be taken giving priority to maintaining service to Company's retail and full requirements customers relative to other sales whenever feasible and as allowed by law.

ENERGY CURTAILMENT PROCEDURE

PRIORITY LEVELS

For the purpose of these procedures, the following Priority Levels have been established:

I. Essential Health and Safety Uses -- to be given special consideration in these procedures shall, insofar as the situation permits, include the following types of use

A. "Hospitals", which shall be limited to institutions providing medical care to patients.

B. "Life Support Equipment", which shall be limited to kidney machines, respirators, and similar equipment used to sustain the life of a person.

C. "Police Stations and Government Detention Institutions", which shall be limited to essential uses required for police activities and the operation of facilities used for the detention of persons.

D. "Fire Stations", which shall be limited to facilities housing mobile fire-fighting apparatus.

E. "Communication Services", which shall be limited to essential uses required for telephone, telegraph, television, radio and newspaper operations, and operation of state and local emergency services.

F. "Water and Sewage Services", which shall be limited to essential uses required for the supply of water to a community, flood pumping and sewage disposal.

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 107

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, First Revision of Original Sheet No. 107.1
Canceling P.S.C. Electric No. 9, 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 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:

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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 107.1

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

PRIORITY LEVELS (continued)

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Canceling P.S.C. Electric No. 9, 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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Louisville Gas and Electric Company

P.S.C. Electric No. 10, Original Sheet No. 107.2

TERMS AND CONDITIONS

Energy Curtailment and Service Restoration Procedures

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Louisville Gas and Electric Company

P.S.C. Electric No. 9, 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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ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
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Louisville Gas and Electric Company

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P.S.C. Gas No. 9
Canceling P.S.C. Gas No. 8

Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky
www.lge-ku.com

Rates, Terms and Conditions for Furnishing

NATURAL GAS SERVICE

In the seventeen counties of the Louisville, Kentucky, metropolitan area
as depicted on territorial maps as filed with the

PUBLIC SERVICE COMMISSION

OF KENTUCKY

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P.S.C. Gas No. 10
Canceling P.S.C. Gas No. 9

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Tenth Revision of Original Sheet No. 1
Canceling P.S.C. Gas No. 9, Ninth Revision of Original Sheet No. 1

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 1

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 1.1

GENERAL INDEX
Standard Gas Rate Schedules – Terms and Conditions

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 1.1

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Eighth Revision of Original Sheet No. 5
Canceling P.S.C. Gas No. 9, Seventh Revision of Original Sheet No. 5

Standard Rate **RGS**
Residential Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to residential customers for all domestic purposes in private residences, single occupancy apartments, and common-use areas of multi-purpose occupancy buildings when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served. Such customers also include tenants billed for natural gas consumption or use by other tenants at the same premises that are metered separately.

The term "residential" customers shall include customers using gas in a single-family residential dwelling or unit for space-heating, air conditioning, cooking, water-heating, incineration, refrigeration, laundry drying, lighting, incidental heating, or other domestic purposes, including the use of gas in standby electric generation in domestic applications. If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer's Representative) to the Company in conjunction with the "Notice to Company of Changes in Customer's Load" set out in the Customer Responsibilities section of the Terms and Conditions of the Company's Tariff. Additionally, service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other Customers.

RATE

Basic Service Charge:	$13.50 per delivery point per month
Plus a Charge Per 100 Cubic Feet:	
Distribution Cost Component	$ 0.26419
Gas Supply Cost Component	$ 0.56128
Total Gas Charge Per 100 Cubic Feet	$ 0.82547

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

DATE OF ISSUE: October 28, 2014

DATE EFFECTIVE: November 1, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00348 dated October 27, 2014

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 5

Standard Rate **RGS**
Residential Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to residential customers for all domestic purposes in private residences, single occupancy apartments, and common-use areas of multi-purpose occupancy buildings when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served. Such customers also include tenants billed for natural gas consumption or use by other tenants at the same premises that are metered separately.

The term "residential" customers shall include customers using gas in a single-family residential
dwelling or unit for space-heating, air conditioning, cooking, water-heating, incineration,
refrigeration, laundry drying, lighting, incidental heating, personal vehicle fueling, or other T
domestic purposes, including the use of gas in standby electric generation in domestic
applications. If an additional separate point of delivery is requested by a residential customer
to provide gas for use in standby electric generation, customer shall be served under Standard
Rate DGGS. Company shall not be obligated to install an additional service to a residential T
customer for the purpose of the customer installing equipment for either electric standby T
generation or personal vehicle fueling. T

All existing and future installations of equipment for the purpose of providing gas for use in
standby electric generation or personal vehicle fueling shall be reported by the Customer (or T
the Customer's Representative) to the Company in conjunction with the "Notice to Company of
Changes in Customer's Load" set out in the Customer Responsibilities section of the Terms
and Conditions of the Company's Tariff. Additionally, service for gas for use in standby electric
generation and personal vehicle fueling shall be subject to the availability of adequate capacity T
on Company's gas system to perform such service without detriment to its other Customers.

RATE

Basic Service Charge:	$19.00 per delivery point per month	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.21325	R
Gas Supply Cost Component	$ 0.56128	
Total Gas Charge Per 100 Cubic Feet	$ 0.77453	R

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 5.1

Standard Rate **RGS**

Residential Gas Service

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within 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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 5.1

Standard Rate **RGS**

Residential Gas Service

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91
Home Energy Assistance Program	Sheet No. 92

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within 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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Ninth Revision of Original Sheet No. 7
Canceling P.S.C. Gas No. 9, Eighth Revision of Original Sheet No. 7

Standard Rate **VFD**

Volunteer Fire Department Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load. If an additional separate point of delivery is requested by a volunteer fire department qualifying for aid under KRS 95A.262 to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS.

DEFINITION

To be eligible for this rate a volunteer fire department is defined as;

1) having at least 12 members and a chief,
2) having at least one fire fighting apparatus, and
3) half the members must be volunteers.

RATE

Basic Service Charge:	$13.50 per delivery point per month
Plus a Charge Per 100 Cubic Feet:	
Distribution Cost Component	$ 0.26419
Gas Supply Cost Component	$ 0.56128
Total Gas Charge Per 100 Cubic Feet	$ 0.82547

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: October 28, 2014

DATE EFFECTIVE: November 1, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00348 dated October 27, 2014

LG&E Volunteer Fire Department Service Rate VFD was previously located on Sheet No. 7, but is proposed to be moved to Sheet No. 9.

Standard Rate

VFD
Volunteer Fire Department Service

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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

LG&E Volunteer Fire Department Service Rate VFD was previously located on Sheet No. 7, but is proposed to be moved to Sheet No. 9.

LG&E Volunteer Fire Department Service Rate VFD was previously located on Sheet No. 7, but is proposed to be moved to Sheet No. 9.

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 9

Standard Rate **VFD**

Volunteer Fire Department Service

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
Available, in accordance with the provisions of KRS 278.172, to any volunteer fire department qualifying for aid under KRS 95A.262. Service under this rate schedule is at the option of the customer with the customer determining whether service will be provided under this schedule or any other schedule applicable to this load. If an additional separate point of delivery is requested by a volunteer fire department qualifying for aid under KRS 95A.262 to provide gas for use in standby electric generation, customer shall be served under Standard Rate DGGS.

DEFINITION
To be eligible for this rate a volunteer fire department is defined as;

1) having at least 12 members and a chief,
2) having at least one fire fighting apparatus, and
3) half the members must be volunteers.

RATE

Basic Service Charge:	$19.00 per delivery point per month	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.21325	
Gas Supply Cost Component	$ 0.56128	R
Total Gas Charge Per 100 Cubic Feet	$ 0.77453	R

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

LG&E Volunteer Fire Department Service Rate VFD was previously located on Sheet No. 7, but is proposed to be moved to Sheet No. 9.

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 9.1

Standard Rate **VFD**

Volunteer Fire Department Service

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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 10

Standard Rate **CGS**

Firm Commercial Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to customers engaged in commercial activities such as apartment buildings, rooming and boarding dwellings, residential hotels, multi-family row housing, duplexes, other situations where gas is supplied to consumers in two or more dwelling units designed for the primary purposes of residences, and other commercial activities when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination commercial and residential accounts shall be considered commercial if usage for commercial purposes is half or more than half of the total service over the course of a year.

The term “commercial” customers shall include customers using gas in activities related to warehousing, distributing, or selling commodities, providing professional services, wholesale and retail stores, offices, office buildings, hotels, retail bakeries, hospitals, schools, churches, religious or charitable institutions, governmental agencies, other institutions or the like (including local, state, and federal governmental agencies) and for uses other than those involved in manufacturing. Applications related to the use of gas in standby or other electric generation in commercial applications shall not be served under this rate schedule unless (1) such facilities were installed and operating under this Standard Rate CGS before ninety (90) days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000 cubic feet per hour and are not for the generation of electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electric supplies during emergency situations.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer’s Representative) to the Company in conjunction with the “Notice to Company of Changes in Customer’s Load” set out in the Customer Responsibilities section of the Terms and Conditions of the Company’s Tariff. Additionally, service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

This schedule is also applicable to natural gas service for street lighting to such entities as certificated homeowners associations, businesses, and local, state, and federal governmental agencies.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 10

Standard Rate **CGS**

Firm Commercial Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to customers engaged in commercial activities such as apartment buildings, rooming and boarding dwellings, residential hotels, multi-family row housing, duplexes, other situations where gas is supplied to consumers in two or more dwelling units designed for the primary purposes of residences, and other commercial activities when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination commercial and residential accounts shall be considered commercial if usage for commercial purposes is half or more than half of the total service over the course of a year.

The term “commercial” customers shall include customers using gas in activities related to warehousing, distributing, or selling commodities, providing professional services, wholesale and retail stores, offices, office buildings, hotels, retail bakeries, hospitals, schools, churches, religious or charitable institutions, governmental agencies, other institutions or the like (including local, state, and federal governmental agencies) and for uses other than those involved in manufacturing. Applications related to the use of gas in standby or other electric generation in commercial applications shall not be served under this rate schedule unless (1) such facilities were installed and operating under this Standard Rate CGS before ninety (90) days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000 cubic feet per hour and are not for the generation of electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electric supplies during emergency situations.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer’s Representative) to the Company in conjunction with the “Notice to Company of Changes in Customer’s Load” set out in the Customer Responsibilities section of the Terms and Conditions of the Company’s Tariff. Additionally, service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

This schedule is also applicable to natural gas service for street lighting to such entities as certificated homeowners associations, businesses, and local, state, and federal governmental agencies.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Ninth Revision of Original Sheet No. 10.1
Canceling P.S.C. Gas No. 9, Eighth Revision of Original Sheet No. 10.1

Standard Rate **CGS**
Firm Commercial Gas Service

RATE

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 35.00 per delivery point per month
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$175.00 per delivery point per month

Plus a Charge Per 100 Cubic Feet:

Distribution Cost Component	$ 0.20999
Gas Supply Cost Component	0.56128
Total Charge Per 100 Cubic Feet	$ 0.77127

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

Off-Peak Pricing Provision:
The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by $0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: October 28, 2014

DATE EFFECTIVE: November 1, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00348 dated October 27, 2014

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 10.1

Standard Rate **CGS**
Firm Commercial Gas Service

RATE

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 40.00 per delivery point per month	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$180.00 per delivery point per month	I

Plus a Charge Per 100 Cubic Feet:

Distribution Cost Component	$ 0.23445	I
Gas Supply Cost Component	0.56128	
Total Charge Per 100 Cubic Feet	$ 0.79573	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

Off-Peak Pricing Provision:
The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by $0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Weather Normalization Adjustment	Sheet No. 88
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate **CGS**

Firm Commercial Gas Service

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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Standard Rate **CGS**

Firm Commercial Gas Service

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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 15
Canceling P.S.C. Gas No. 9, Original Sheet No. 15

Standard Rate **IGS**
Firm Industrial Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to customers engaged in industrial activities that involve manufacturing or other activities that process, create or change raw or unfinished materials into another form or product when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination industrial and commercial accounts shall be considered industrial if usage for industrial purposes is half or more than half of the total service over the course of a year.

The term “industrial” customers shall include customers involved in activities using gas primarily in a process or processes which either involve the extraction of raw materials from the earth, or a change of raw or unfinished materials into another form or product through the application of heat or heat treating, steam agitation, evaporation, baking, extraction, drying, distilling, asphalt production, and for other similar uses. Applications related to the use of gas in standby or other electric generation in industrial applications shall not be served under this rate schedule unless (1) such facilities were installed and operating under this Standard Rate IGS before ninety (90) days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000 cubic feet per hour and are not for the generation of electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electric supplies during emergency situations.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer’s Representative) to the Company in conjunction with the “Notice to Company of Changes in Customer’s Load” set out in the Customer Responsibilities section of the Terms and Conditions of the Company’s Tariff. Additionally, Service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 15

Standard Rate **IGS**
Firm Industrial Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to customers engaged in industrial activities that involve manufacturing or other activities that process, create or change raw or unfinished materials into another form or product when supplied at a single point of delivery and where distribution mains are adjacent to the premises to be served.

Combination industrial and commercial accounts shall be considered industrial if usage for industrial purposes is half or more than half of the total service over the course of a year.

The term “industrial” customers shall include customers involved in activities using gas primarily
in a process or processes which either involve the extraction of raw materials from the earth, or
a change of raw or unfinished materials into another form or product through the application of
heat or heat treating, steam agitation, evaporation, baking, extraction, drying, distilling, asphalt
production, vehicular fueling of internal combustion engines, and for other similar uses. T
Customers using natural gas for vehicular fueling of internal combustion engines must also T
elect service under Rider NGV. Applications related to the use of gas in standby or other T
electric generation in industrial applications shall not be served under this rate schedule unless
(1) such facilities were installed and operating under this Standard Rate IGS before ninety (90)
days after August 1, 2010, or (2) such facilities have a total connected load of less than 2,000
cubic feet per hour and are not for the generation of electricity for further distribution, for sale in
the open market, or for any purpose other than to provide Customer with standby electric
supplies during emergency situations.

All existing and future installations of equipment for the purpose of providing gas for use in standby electric generation shall be reported by the Customer (or the Customer’s Representative) to the Company in conjunction with the “Notice to Company of Changes in Customer’s Load” set out in the Customer Responsibilities section of the Terms and Conditions of the Company’s Tariff. Additionally, Service for gas for use in standby electric generation shall be subject to the availability of adequate capacity on Company’s gas system to perform such service without detriment to its other Customers.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Ninth Revision of Original Sheet No. 15.1
Canceling P.S.C. Gas No. 9, Eighth Revision of Original Sheet No. 15.1

Standard Rate **IGS**
Firm Industrial Gas Service

RATE

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 35.00 per delivery point per month
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$175.00 per delivery point per month

Plus a Charge Per 100 Cubic Feet:

Distribution Cost Component	$ 0.21452
Gas Supply Cost Component	$ 0.56128
Total Charge Per 100 Cubic Feet	$ 0.77580

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

Off-Peak Pricing Provision:
The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by $0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DATE OF ISSUE: October 28, 2014

DATE EFFECTIVE: November 1, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00348 dated October 27, 2014

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 15.1

Standard Rate **IGS**
Firm Industrial Gas Service

RATE

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 40.00 per delivery point per month	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$180.00 per delivery point per month	I

Plus a Charge Per 100 Cubic Feet:

Distribution Cost Component	$ 0.24305	I
Gas Supply Cost Component	$ 0.56128	
Total Charge Per 100 Cubic Feet	$ 0.80433	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

Off-Peak Pricing Provision:
The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by $0.05 per 100 cubic feet during the seven off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

MINIMUM CHARGE

The Basic Service Charge shall be the minimum charge.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

Canceling P.S.C. Gas No. 9, Original Sheet No. 15.2

Standard Rate **IGS**

Firm Industrial Gas Service

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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 15.2

Standard Rate **IGS**

Firm Industrial Gas Service

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: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 20
Canceling P.S.C. Gas No. 9, Original Sheet No. 20

Standard Rate **AAGS**
As-Available Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rate schedule is designed to make available to commercial and industrial customers quantities of natural gas that Company may from time to time have available for sale without impairment of service to customers served under other higher priority rate schedules, and which can be supplied from Company's existing distribution system, subject to the special conditions hereinafter set forth.

This rate shall not be available for gas loads which are predominantly space heating in character. In order to ensure that this rate schedule shall not be available for loads which are predominantly space heating in character and which do not consume substantial quantities of gas throughout the year, customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual Delivery Point.

Customers served under Rate G-6 and Rate G-7 as of the first effective date of this Rate AAGS shall have the right to elect service under Rate AAGS, Rate CGS, or Rate IGS. Such Customers that elect to transfer from either Rate G-6 or Rate G-7 to service under Rate AAGS may do so without complying with the requirement set forth above that customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual Delivery Point. Customers not electing service under either Rate CGS or Rate IGS shall receive service hereunder upon the first effective date hereof, irrespective of the November 1 start-date set forth in “Contract-Term” below.

COMPANY NOT OBLIGATED TO CONTINUE SERVICE

Company shall have the right to discontinue the supply of natural gas wholly or in part for such period or periods as, in the sole judgment of Company, may be necessary or advisable to enable it to supply the full gas requirements of its customers served under higher priority rate schedules. Nothing herein shall prevent Company from expanding its obligations under such other rate schedules. Company may decline to accept any additional contracts for service hereunder.

CONTRACT TERM

Customers served under Rate AAGS shall enter a written contract with Company more fully described in the Special Terms and Conditions of this rate schedule. The minimum contract term for service hereunder shall be for a period of at least one (1) year and shall commence on

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 20

Standard Rate **AAGS**
As-Available Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rate schedule is designed to make available to commercial and industrial customers quantities of natural gas that Company may from time to time have available for sale without impairment of service to customers served under other higher priority rate schedules, and which can be supplied from Company's existing distribution system, subject to the special conditions hereinafter set forth.

This rate shall not be available for gas loads which are predominantly space heating in character. In order to ensure that this rate schedule shall not be available for loads which are predominantly space heating in character and which do not consume substantial quantities of gas throughout the year, customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual Delivery Point.

Customers served under Rate G-6 and Rate G-7 as of the first effective date of this Rate AAGS shall have the right to elect service under Rate AAGS, Rate CGS, or Rate IGS. Such Customers that elect to transfer from either Rate G-6 or Rate G-7 to service under Rate AAGS may do so without complying with the requirement set forth above that customers served hereunder shall be required to consume, when gas is available, at least 50 Mcf each day during each billing cycle at each individual Delivery Point. Customers not electing service under either Rate CGS or Rate IGS shall receive service hereunder upon the first effective date hereof, irrespective of the November 1 start-date set forth in “Contract-Term” below.

COMPANY NOT OBLIGATED TO CONTINUE SERVICE

Company shall have the right to discontinue the supply of natural gas wholly or in part for such period or periods as, in the sole judgment of Company, may be necessary or advisable to enable it to supply the full gas requirements of its customers served under higher priority rate schedules. Nothing herein shall prevent Company from expanding its obligations under such other rate schedules. Company may decline to accept any additional contracts for service hereunder.

CONTRACT TERM

Customers served under Rate AAGS shall enter a written contract with Company more fully described in the Special Terms and Conditions of this rate schedule. The minimum contract term for service hereunder shall be for a period of at least one (1) year and shall commence on

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Ninth Revision of Original Sheet No. 20.1
Canceling P.S.C. Gas No. 9, Eighth Revision of Original Sheet No. 20.1

Standard Rate **AAGS**
As-Available Gas Service

CONTRACT TERM (continued)

November 1 and be effective through the following October 31, and year to year thereafter, unless terminated by either Company or Customer upon prior written notice on or before the April 30 preceding the October 31 termination date.

Any customer served under Rate CGS or Rate IGS shall provide notice to Company by April 30 of its request for service to be effective commencing on the following November 1.

RATE

Basic Service Charge:
$275.00 per delivery point per month

Plus a Charge Per Mcf	
Distribution Cost Component	$ 0.6086
Gas Supply Cost Component	$ 5.6128
Total Charge Per Mcf	$ 6.2214

The "Gas Supply Cost Component" as shown above is the cost per Mcf determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet Nos. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

PENALTY FOR FAILURE TO INTERRUPT

Company shall have the right to interrupt sales service under this rate schedule upon eighteen (18) hours' prior notice. Provision of oral notice by telephone to Customer shall be deemed proper notice of interruption of service under this rate schedule.

DATE OF ISSUE: October 28, 2014

DATE EFFECTIVE: November 1, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00348 dated October 27, 2014

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 20.1

Standard Rate **AAGS**
As-Available Gas Service

CONTRACT TERM (continued)

November 1 and be effective through the following October 31, and year to year thereafter, unless terminated by either Company or Customer upon prior written notice on or before the April 30 preceding the October 31 termination date.

Any customer served under Rate CGS or Rate IGS shall provide notice to Company by April 30 of its request for service to be effective commencing on the following November 1.

RATE

Basic Service Charge:
$400.00 per delivery point per month I

Plus a Charge Per Mcf		
Distribution Cost Component	$ 0.8285	I
Gas Supply Cost Component	$ 5.6128	
Total Charge Per Mcf	$ 6.4413	I

The "Gas Supply Cost Component" as shown above is the cost per Mcf determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet Nos. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

PENALTY FOR FAILURE TO INTERRUPT

Company shall have the right to interrupt sales service under this rate schedule upon eighteen (18) hours' prior notice. Provision of oral notice by telephone to Customer shall be deemed proper notice of interruption of service under this rate schedule.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 20.2
Canceling P.S.C. Gas No. 9, Original Sheet No. 20.2

Standard Rate **AAGS**
As-Available Gas Service

PENALTY FOR FAILURE TO INTERRUPT (continued)

In addition to the charges set forth above, if the Customer fails to discontinue the consumption of natural gas at its facility at the conclusion of the eighteen- (18-) hour notice period, Company may charge the Customer the following penalty for each Mcf used during the period of interruption in addition to any other remedy available to Company, including, but not limited to, immediate termination of service under this rate schedule, irrespective of the provisions set forth on “Contract Term”, and immediate transfer by Company to either Rate CGS or Rate IGS, as applicable.

Customer shall be charged a per Mcf penalty charge equal to $15.00 plus the mid-point price posted in "*Platts Gas Daily*" for Dominion--South Point on the day to which such interruption of service is applicable, plus any other charges under this rate schedule for such unauthorized usage by Customer that occurs following the conclusion of the eighteen- (18-) hour notice of interruption by Company to Customer.

If Customer is delivering quantities of gas to Company pursuant to Rider TS during such period of interruption, the charge described in the immediately preceding paragraph shall be applicable only to those quantities used by customer in excess of those being delivered by Customer to Company.

Company shall not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of this rate schedule. Payment of penalty charges hereunder shall not be considered an exclusive remedy for failure to comply with the notice of interruption, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

SPECIAL TERMS AND CONDITIONS

1. Service shall be supplied hereunder only at such times and in such volumes as Company, in its sole judgment, determines that gas is available for such service without impairment of service supplied under other rate schedules.

2. Each customer served hereunder shall be required to enter into a written contract specifying, among other things, realistic monthly requirements for gas under this rate schedule. Such volumes shall be used as the basis for apportionment of gas when the total customer requirements exceed the quantity of gas available for service hereunder.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 20.2

Standard Rate **AAGS**
As-Available Gas Service

PENALTY FOR FAILURE TO INTERRUPT (continued)

In addition to the charges set forth above, if the Customer fails to discontinue the consumption of natural gas at its facility at the conclusion of the eighteen- (18-) hour notice period, Company may charge the Customer the following penalty for each Mcf used during the period of interruption in addition to any other remedy available to Company, including, but not limited to, immediate termination of service under this rate schedule, irrespective of the provisions set forth on “Contract Term”, and immediate transfer by Company to either Rate CGS or Rate IGS, as applicable.

Customer shall be charged a per Mcf penalty charge applicable to any unauthorized takes of gas during the period of interruption (excluding Pilot Light Requirements where applicable) equal to $15.00 plus the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the period of interruption that falls into each monthly billing cycle, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the period of interruption that falls into each monthly billing cycle. Such penalty for failure to interrupt shall be in addition to any other charges under this rate schedule for such unauthorized usage by Customer that occurs following the conclusion of the eighteen- (18-) hour notice of interruption by Company to Customer. T

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Company shall not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of this rate schedule. Payment of penalty charges hereunder shall not be considered an exclusive remedy for failure to comply with the notice of interruption, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

SPECIAL TERMS AND CONDITIONS

1. Service shall be supplied hereunder only at such times and in such volumes as Company, in its sole judgment, determines that gas is available for such service without impairment of service supplied under other rate schedules.

2. Each customer served hereunder shall be required to enter into a written contract specifying, among other things, realistic monthly requirements for gas under this rate schedule. Such volumes shall be used as the basis for apportionment of gas when the total customer requirements exceed the quantity of gas available for service hereunder.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 20.3
Canceling P.S.C. Gas No. 9, Original Sheet No. 20.3

Standard Rate **AAGS**
As-Available Gas Service

SPECIAL TERMS AND CONDITIONS (continued)

3. The customer shall contract under this rate schedule for a specified quantity of gas stated in terms of maximum required deliveries in Mcf per day. On no day shall Company be obligated to supply gas in excess of such contract quantity. In no case will Company be obligated to supply gas to Customer at greater volumes and greater rates of flow than those historically delivered by Company to Customer.

4. Customer shall discontinue taking service upon applicable notice by Company to do so.

5. No gas service whatsoever to Customer's equipment or process served hereunder shall be supplied or permitted to be taken under any other of Company's gas rate schedules during periods of interruption.

6. Upon commencement of service hereunder, Customer shall be required to certify that Customer's alternate fuel facilities are operational and alternate fuel is on site and capable of use. Company may, at its discretion, verify such certification through physical inspection of Customer's facility. In the event that Customer does not have alternate fuel facilities, Customer shall certify that the processes which utilize gas delivered hereunder are capable of complete discontinuance of natural gas use. Company may request Customer to verify either of the foregoing alternatives on an annual basis on or before October 1 of each year. Failure of Customer to annually certify either of the above alternatives shall result, in the sole discretion of Company, in immediate termination of service under this rate schedule and the immediate transfer to the appropriate firm sales rate schedule, either Rate CGS or Rate IGS.

7. Service hereunder must be supplied through a separate meter and physically isolated from any other service provided by Company under other rate schedules.

8. Company shall not be obligated to install or construct any facilities (other than necessary meters and regulators) in order to provide service hereunder.

9. Any Customer contracting for service hereunder, other than a Customer transferring from either Rate G-6 or Rate G-7 as stipulated above, may be required, in the sole discretion of Company, either prior to electing service hereunder or at anytime thereafter, to have appropriate remote metering devices. The remote metering devices allow Company to monitor the Customer's usage and determine compliance with notice of interruption of service hereunder. The Customer shall be responsible for the cost of the remote metering equipment and the cost of its installation.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 20.3

Standard Rate **AAGS**
As-Available Gas Service

SPECIAL TERMS AND CONDITIONS (continued)

3. The customer shall contract under this rate schedule for a specified quantity of gas stated in terms of maximum required deliveries in Mcf per day. On no day shall Company be obligated to supply gas in excess of such contract quantity. In no case will Company be obligated to supply gas to Customer at greater volumes and greater rates of flow than those historically delivered by Company to Customer.

4. Customer shall discontinue taking service upon applicable notice by Company to do so.

5. No gas service whatsoever to Customer's equipment or process served hereunder shall be supplied or permitted to be taken under any other of Company's gas rate schedules during periods of interruption.

6. Upon commencement of service hereunder, Customer shall be required to certify that Customer's alternate fuel facilities are operational and alternate fuel is on site and capable of use. Company may, at its discretion, verify such certification through physical inspection of Customer's facility. In the event that Customer does not have alternate fuel facilities, Customer shall certify that the processes which utilize gas delivered hereunder are capable of complete discontinuance of natural gas use. Company may request Customer to verify either of the foregoing alternatives on an annual basis on or before October 1 of each year. Failure of Customer to annually certify either of the above alternatives shall result, in the sole discretion of Company, in immediate termination of service under this rate schedule and the immediate transfer to the appropriate firm sales rate schedule, either Rate CGS or Rate IGS.

7. Service hereunder must be supplied through a separate meter and physically isolated from any other service provided by Company under other rate schedules.

8. Company shall not be obligated to install or construct any facilities (other than necessary meters and regulators) in order to provide service hereunder.

9. Any Customer contracting for service hereunder, other than a Customer transferring from either Rate G-6 or Rate G-7 as stipulated above, may be required, in the sole discretion of Company, either prior to electing service hereunder or at any time thereafter, to have appropriate remote metering devices. The remote metering devices allow Company to monitor the Customer's usage and determine compliance with notice of interruption of
service hereunder. The Customer shall reimburse Company for the cost of the remote T
metering equipment, for any modifications to Company facilities, and for the replacement of T
any existing meters required in order to facilitate the functioning of the remote metering. T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 20.4

Standard Rate **AAGS**
As-Available Gas Service

SPECIAL TERMS AND CONDITIONS (continued)

Any Customer required to have remote metering as described above shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

Any Customer required to have remote metering shall be responsible for providing the necessary and adequate electric and telephone service to provide this metering within thirty (30) days of Company's notice to Customer that such remote metering shall be required. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide such remote metering.

DUE DATE OF BILL
Customer's payment will be due within 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.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 20.4

Standard Rate **AAGS**
As-Available Gas Service

SPECIAL TERMS AND CONDITIONS (continued)

Any Customer required to have remote metering as described above shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

Any Customer required to have remote metering shall be responsible for providing the necessary and adequate electric and telephone service to provide this metering within thirty (30) days of Company's notice to Customer that such remote metering shall be required. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide such remote metering.

DUE DATE OF BILL
Customer's payment will be due within 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.

TERMS AND CONDITIONS
Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict, nor inconsistent, with the specific provisions hereof.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 30
Canceling P.S.C. Gas No. 9, Original Sheet No. 30

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to existing commercial and industrial customers who consume at least 50 Mcf each day at each individual Delivery Point during each month of the twenty-four (24) months prior to the March 31 service request date, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's Pipeline Transporter, and have requested Company to utilize its system to transport, by displacement, such customer-owned gas to Customer's place of utilization. Customers electing to transfer from another service shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rate schedule shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30.

For new customers whose historical gas consumption is not available, Company will determine Customer’s eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Any such transportation service hereunder shall be conditioned on Company being granted a reduction in billing demands by its Pipeline Transporter corresponding to the Customer's applicable transportation quantities.

Transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Service under this rate schedule shall not be available to customers with a Maximum Daily Quantity (“MDQ”) in excess of 20,000 Mcf/day. In the event that Customer’s MDQ exceeds 20,000 Mcf/day, Company may terminate service under this rate schedule upon thirty (30) days prior written notice. Additionally, customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer’s MDQ, are not eligible for service under this rate schedule.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to existing commercial and industrial customers who consume at least 50 Mcf each day at each individual Delivery Point during each month of the twenty-four (24) months prior to the March 31 service request date, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's Pipeline Transporter, and have requested Company to utilize its system to transport, by displacement, such customer-owned gas to Customer's place of utilization. Customers electing to transfer from another service shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rate schedule shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30.

For new customers whose historical gas consumption is not available, Company will determine Customer’s eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Customers using natural gas for vehicular fueling of internal combustion engines must also T
elect service under Rider NGV. T

Any such transportation service hereunder shall be conditioned on Company being granted a reduction in billing demands by its Pipeline Transporter corresponding to the Customer's applicable transportation quantities.

Transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Service under this rate schedule shall not be available to customers with a Maximum Daily Quantity (“MDQ”) in excess of 20,000 Mcf/day. In the event that Customer’s MDQ exceeds 20,000 Mcf/day, Company may terminate service under this rate schedule upon thirty (30) days prior written notice. Additionally, customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer’s MDQ, are not eligible for service under this rate schedule.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 30.1
Canceling P.S.C. Gas No. 9, Original Sheet No. 30.1

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

CHARACTER OF SERVICE

Transportation service under this rate schedule shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter (“Receipt Point”) to the Delivery Point at the Customer's place of utilization (“Delivery Point”), subject to paragraph 6 of the Special Terms and Conditions.

Due to the physical configuration of Company’s system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company's sole obligation hereunder is to redeliver Customer's gas from the Receipt Point to the Delivery Point. Accordingly, Company has no obligation to deliver to the Customer a volume of gas, either daily or monthly, which differs from the volume delivered to Company at the Receipt Point.

Company will provide service to meet imbalances only on an as-available basis. For purposes used herein, “Imbalances” are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point. When Company can provide such service, the Utilization Charge for Daily Imbalances shall apply to daily imbalances in excess of ±5% of the delivered volume of gas as set forth herein. Company shall issue an Operational Flow Order as set forth herein during periods when service cannot be provided to meet daily imbalances.

Customers served under this rate may elect to become a member of an FT Pool pursuant to Rider PS-FT.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, and any other charges set forth herein, the following charges shall apply.

Administrative Charge: $400.00 per Delivery Point per month

Distribution Charge Per Mcf: $0.43

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rate FT. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rate FT in order to recover from (or refund to) transferring sales customers any under- or over-

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.1

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

CHARACTER OF SERVICE

Transportation service under this rate schedule shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter (“Receipt Point”) to the Delivery Point at the Customer's place of utilization (“Delivery Point”), subject to paragraph 6 of the Special Terms and Conditions.

Due to the physical configuration of Company’s system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company's sole obligation hereunder is to redeliver Customer's gas from the Receipt Point to the Delivery Point. Accordingly, Company has no obligation to deliver to the Customer a volume of gas, either daily or monthly, which differs from the volume delivered to Company at the Receipt Point.

Company will provide service to meet imbalances only on an as-available basis. For purposes used herein, “Imbalances” are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point. When Company can provide such service, the Utilization Charge for Daily Imbalances shall apply to daily imbalances in excess of ±5% of the delivered volume of gas as set forth herein. Company shall issue an Operational Flow Order as set forth herein during periods when service cannot be provided to meet daily imbalances.

Customers served under this rate may elect to become a member of an FT Pool pursuant to Rider PS-FT.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, and any other charges set forth herein, the following charges shall apply.

Administrative Charge: $550.00 per Delivery Point per month I

Distribution Charge Per Mcf: $0.4431 I

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rate FT. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rate FT in order to recover from (or refund to) transferring sales customers any under- or over-

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Ninth Revision of Original Sheet No. 30.2
Canceling P.S.C. Gas No. 9, Eighth Revision of Original Sheet No. 30.2

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

RATE (continued)

collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause ("GSC") applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company's quarterly Gas Supply Clause filings.

For customers electing service under Rate FT effective November 1, 2013,
the Gas Cost True-Up Charge shall be:

$(0.0584) per Mcf for Bills Rendered On and After November 1, 2014

For customers electing service under Rate FT effective November 1, 2014,
the Gas Cost True-Up Charge shall be:

$0.5669 per Mcf for Bills Rendered On and After November 1, 2014

Minimum Daily Threshold Requirement and Charge: When Customer's daily usage falls below the Minimum Daily Threshold Requirement, Customer will be charged a Minimum Daily Threshold Charge equal to the difference between the Minimum Daily Threshold Requirement and the Customer's actual consumption in Mcf for that day multiplied by the Distribution Charge hereunder. The Minimum Daily Threshold Requirement is equal to the minimum daily volume of 50 Mcf. Such Minimum Daily Threshold Charge shall be accumulated for each day of the applicable month and billed during that month in accordance with the following formula:

Minimum Daily Threshold Charge =

(Minimum Daily Threshold minus Customer Usage on Given Day) times the Distribution Charge

Such daily amount shall be accumulated for each day of the month and the total will be applied to Customer's bill.

Payment of the Minimum Daily Threshold Charge is not a remedy for Customer's failure to meet the Minimum Daily Threshold Requirement for service under Rate FT. In the event that Customer does not meet the Minimum Daily Threshold Requirement for one-hundred twenty (120) days during a given Contract Year, service to Customer under Rate FT may be discontinued by Company. Customer will receive thirty (30) days prior written notice that Customer will be removed from Rate FT and returned to firm sales service under either Rate CGS or IGS as applicable.

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State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.2

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

RATE (continued)

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DATE OF ISSUE: November 26, 2014

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 30.3
Canceling P.S.C. Gas No. 9, Original Sheet No. 30.3

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

RATE (continued)

Other: In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then Customer shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

DUE DATE OF BILL

Customer's payment will be due within 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

IMBALANCES

Company will calculate on a daily and monthly basis the Customer's imbalance resulting from the difference between the metered usage of the Customer and the volumes that the Customer has delivered into Company's system. This will be calculated as follows:

Imbalance = Metered Usage - Delivered Volume

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volume}}$$

The term “day” or “daily” shall mean the period of twenty-four (24) consecutive hours beginning at 10:00 a.m., Eastern Clock Time.

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State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.3

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

RATE (continued)

Other: In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then Customer shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

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Company will calculate on a daily and monthly basis the Customer's imbalance resulting from the difference between the metered usage of the Customer and the volumes that the Customer has delivered into Company's system. This will be calculated as follows:

Imbalance = Metered Usage - Delivered Volume

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volume}}$$

The term “day” or “daily” shall mean the period of time corresponding to the gas day as T
observed by the Pipeline Transporter as adjusted for local time. T

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 30.4
Canceling P.S.C. Gas No. 9, Original Sheet No. 30.4

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from Customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lowest daily mid-point price posted in "*Platts Gas Daily*" for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

When Total Net Negative Imbalance Percentage is:	The following percentage shall be multiplied by the above-referenced "*Platts Gas Daily*" price for Dominion South Point:
0% to <u><</u>5%	100%
>5% to <u><</u>10%	90%
>10% to <u><</u>15%	80%
>15% to <u><</u>20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall be billed for the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the highest daily mid-point price posted in "*Platts Gas Daily*" for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-referenced "*Platts Gas Daily*" price for Dominion South Point:
0% to <u><</u>5%	100%
>5% to <u><</u>10%	110%
>10% to <u><</u>15%	120%
>15% to <u><</u>20%	130%
>20%	140%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a Customer with a monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.4

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from Customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either T (a) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows:

When Total Net Negative Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount: T T
0% to <u><</u>5%	100%
>5% to <u><</u>10%	90%
>10% to <u><</u>15%	80%
>15% to <u><</u>20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either T (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Sixth Revision of Original Sheet No. 30.5
Canceling P.S.C. Gas No. 9, Fifth Revision of Original Sheet No. 30.5

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

All such adjustments shall be shown and included on the Customer's monthly bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

UTILIZATION CHARGE FOR DAILY IMBALANCES

Should an imbalance exceed ±5% of the delivered volume of gas on any day when an Operational Flow Order (as described below) has not been issued, then Company shall charge the Utilization Charge for Daily Imbalances times the recorded imbalance greater than ±5% of the delivered volume of gas for each daily occurrence. The Utilization Charge for Daily Imbalances is the sum of the following:

Daily Demand Charge:	$0.1576 per Mcf
Daily Storage Charge:	<u>$0.1833</u>
Utilization Charge for Daily Imbalances:	$0.3409 per Mcf

Note: The Daily Demand Charge may change with each filing of the GSCC.

These charges are in addition to any other charges set forth herein. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed ±5% of the delivered volume. Company shall not have an obligation to provide balancing service for any volumes of gas hereunder.

OPERATIONAL FLOW ORDERS

Company shall have the right to issue an Operational Flow Order ("OFO") which will require actions by Customer to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. Customer shall be responsible for complying with the directives contained in the OFO.

Notice of an OFO shall be provided to Customer at least twenty-four (24) hours prior to the beginning of the gas day for which the OFO is in effect and shall include information related to the OFO. Customer shall respond to an OFO by adjusting its deliveries to Company's system as directed in the OFO within the specified timeframe. If Customer is a member of an FT Pool,

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State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.5

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

The appropriate percentage shall be dependent on the Customer's monthly imbalance percentage to be applied as follows: T

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:
0% to ≤5%	100%
>5% to ≤10%	110%
>10% to ≤15%	120%
>15% to ≤20%	130%
>20%	140%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a Customer with a monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the Customer's monthly bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

UTILIZATION CHARGE FOR DAILY IMBALANCES

Should an imbalance exceed ±5% of the delivered volume of gas on any day when an Operational Flow Order (as described below) has not been issued, then Company shall charge the Utilization Charge for Daily Imbalances times the recorded imbalance greater than ±5% of the delivered volume of gas for each daily occurrence. The Utilization Charge for Daily Imbalances is the sum of the following:

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 30.6
Canceling P.S.C. Gas No. 9, Original Sheet No. 30.6

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

OPERATIONAL FLOW ORDERS (continued)

it is the responsibility of the FT Pool Manager, not Company, to convey OFOs to Customers in its FT Pool.

Upon issuance of an OFO, Company will direct Customer to comply with one of the following conditions: (a) Customer must take delivery of an amount of natural gas from Company that is no more than the daily amount being delivered by the Pipeline Transporter to Company for Customer; or (b) Customer must take delivery of an amount of natural gas from Company that is no less than the daily amount being delivered by the Pipeline Transporter to Company for Customer. Customer shall respond to an OFO by either adjusting its deliveries to Company's system or its consumption at its facility. All volumes taken by Customer in excess of volumes delivered by Pipeline Transporter to Company for Customer in violation of the above "condition (a)" OFO shall constitute an unauthorized receipt by Customer from Company. All volumes taken by Customer less than volumes delivered by Pipeline Transporter to Company for Customer in violation of "condition (b)" OFO shall constitute an unauthorized delivery by Customer to Company. Customer shall be subject to the OFO Charge on the day for which the OFO was violated, plus the applicable UCDI charges and any other charges under this rate schedule for such unauthorized receipts or deliveries that occur

Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT.

The OFO Charge shall be equal to $15.00 plus the mid-point price posted in "*Platts Gas Daily"* for Dominion South Point per Mcf on the day for which the OFO was violated, plus any other charges under this rate schedule.

Company will not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of an OFO. Payment of OFO Charges hereunder shall not be considered an exclusive remedy for failure to comply with the OFO, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

OPTIONAL SALES AND PURCHASE TRANSACTION

Customer may agree to sell its natural gas supplies to Company, and Company may agree to purchase natural gas supplies from Customer pursuant to Company's Curtailment Rules. If Company purchases natural gas from Customer, such gas will not be redelivered to Customer, and Customer shall discontinue or otherwise interrupt the usage of such natural gas.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.6

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

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UTILIZATION CHARGE FOR DAILY IMBALANCES (continued)

Daily Demand Charge:	$0.1576 per Mcf
Daily Storage Charge:	<u>$0.1833</u>
Utilization Charge for Daily Imbalances:	$0.3409 per Mcf

Note: The Daily Demand Charge may change with each filing of the GSCC.

These charges are in addition to any other charges set forth herein. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed ±5% of the delivered volume unless an OFO has been issued. If an OFO has been issued, the Utilization Charge for Daily Imbalances shall apply to daily imbalances which exceed 0% for customers in violation of the OFO directive, either "condition (a)" or "condition (b)" as applicable and further described below under "Operational Flow Orders". Customers not in violation of the OFO directive, either "condition (a)" or "condition (b)" as applicable, will continue to be assessed the Utilization Charge for Daily Imbalances on volumes which exceed the 5% daily tolerance. Company shall not have an obligation to provide balancing service for any volumes of gas hereunder.

OPERATIONAL FLOW ORDERS

Company shall have the right to issue an Operational Flow Order ("OFO") which will require actions by Customer to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. Customer shall be responsible for complying with the directives contained in the OFO.

Notice of an OFO shall be provided to Customer at least twenty-four (24) hours prior to the beginning of the gas day for which the OFO is in effect and shall include information related to the OFO. Customer shall respond to an OFO by adjusting its deliveries to Company's system as directed in the OFO within the specified timeframe. If Customer is a member of an FT Pool, it is the responsibility of the FT Pool Manager, not Company, to convey OFOs to Customers in its FT Pool.

Upon issuance of an OFO, Company will direct Customer to comply with one of the following conditions: (a) Customer must take delivery of an amount of natural gas from Company that is no more than the daily amount being delivered by the Pipeline Transporter to Company for Customer; or (b) Customer must take delivery of an amount of natural gas from Company that T

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 30.7
Canceling P.S.C. Gas No. 9, Original Sheet No. 30.7

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

RETURN TO FIRM SALES SERVICE

Return to firm sales service is contingent upon the ability of Company to secure the appropriate quantities of gas supply and transportation capacity with Company's Pipeline Transporter, as determined solely by Company.

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rate schedule. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

The Customer shall be responsible for the cost of this remote metering equipment and the cost of its installation.

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide remote metering by October 1 of the year that the Customer's Rate FT service becomes effective. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be transported by Company for Customer, Delivery Points, timing of receipts and deliveries of gas by Company, and any other matters relating to individual Customer circumstances.

2. As further described below, Customer shall specify to Company the daily volume of gas required by Customer. Such volume shall be stated in Mcf/day and converted to MMBtu/day using a standard conversion factor as may be specified by Company from time to time. At least ten (10) days prior to the beginning of each month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for Customer's account. Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by Customer to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from Customer daily nominations, or changes thereto, that are made after the daily deadline for

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 30.7

Standard Rate **FT**
Firm Transportation Service (Transportation Only)

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OPERATIONAL FLOW ORDERS (continued)

is no less than the daily amount being delivered by the Pipeline Transporter to Company for Customer. Customer shall respond to an OFO by either adjusting its deliveries to Company's system or its consumption at its facility. All volumes taken by Customer in excess of volumes delivered by Pipeline Transporter to Company for Customer in violation of the above "condition (a)" OFO shall constitute an unauthorized receipt by Customer from Company. All volumes taken by Customer less than volumes delivered by Pipeline Transporter to Company for Customer in violation of the above "condition (b)" OFO shall constitute an unauthorized delivery by Customer to Company. Unauthorized receipts or deliveries during the effectiveness of an OFO shall be subject to an OFO Charge per Mcf for each Mcf of unauthorized receipts or deliveries, as applicable. Customer shall be subject to the OFO Charge on the day for which the OFO was violated, plus the applicable UCDI charges and any other charges under this rate schedule for such unauthorized receipts or deliveries that occur.

Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT.

The OFO Charge per Mcf shall be equal to $15.00 plus the higher of the following: either (a) the daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the OFO was violated, or (b) the daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the OFO was violated. Such OFO Charge shall be in addition to any other charges under this rate schedule.Company will not be required to provide service under this rate schedule for any Customer that does not comply with the terms or conditions of an OFO. Payment of OFO Charges hereunder shall not be considered an exclusive remedy for failure to comply with the OFO, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

OPTIONAL SALES AND PURCHASE TRANSACTION

Customer may agree to sell its natural gas supplies to Company, and Company may agree to purchase natural gas supplies from Customer pursuant to Company's Curtailment Rules. If Company purchases natural gas from Customer, such gas will not be redelivered to Customer, and Customer shall discontinue or otherwise interrupt the usage of such natural gas.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

SPECIAL TERMS AND CONDITIONS (continued)

such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company. Company will not be obligated to utilize its underground storage capacity for purposes of this service.

3. In no case will Company be obligated to deliver gas, including both gas transported and gas sold, to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be referred to as the Maximum Daily Quantity (“MDQ”). The MDQ is the maximum daily volume of gas, as determined by Company, based on Customer’s historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine the MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis.
4. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.
5. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.
6. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.
7. Should Customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will not be obligated hereunder to provide standby quantities for purposes of supplying such Customer requirements.
8. Company shall not be required to render service under this rate schedule to any Customer that fails to comply with any and all of the terms and conditions of this rate schedule.

TERMS AND CONDITIONS

Service under this rate is subject to Company’s Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

RETURN TO FIRM SALES SERVICE

Return to firm sales service is contingent upon the ability of Company to secure the appropriate quantities of gas supply and transportation capacity with Company's Pipeline Transporter, as determined solely by Company.

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rate schedule. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

The Customer shall reimburse Company for the cost of this remote metering equipment and the T
cost of its installation, including any modifications to Company facilities and the replacement of T
any existing meters required in order to facilitate the functioning of the remote metering. T

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer’s piping, in order to facilitate the installation and operation of such remote metering.

The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide remote metering by October 1 of the year that the Customer’s Rate FT service becomes effective. Electric and telephone services installed for this equipment shall conform to Company’s specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be transported by Company for Customer, Delivery Points, timing of receipts and deliveries of gas by Company, and any other matters relating to individual Customer circumstances.
2. As further described below, Customer shall specify to Company the daily volume of gas required by Customer. Such volume shall be stated in Mcf/day and converted to MMBtu/day using a standard conversion factor as may be specified by Company from time to time. At least ten (10) days prior to the beginning of each month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

LG&E Firm Transportation Service (Transportation Only) Rate FT is now contained on eleven pages instead of the current nine pages.

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

T

SPECIAL TERMS AND CONDITIONS (continued)

system for Customer's account. Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by Customer to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from Customer daily nominations, or changes thereto, that are made after the daily deadline for Transporter, shall be provided by Customer to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from Customer daily nominations, or changes thereto, that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company. Company will not be obligated to utilize its underground storage capacity for purposes of this service.

3. In no case will Company be obligated to deliver gas, including both gas transported and gas sold, to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be referred to as the Maximum Daily Quantity ("MDQ"). The MDQ is the maximum daily volume of gas, as determined by Company, based on Customer's historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine the MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis.

4. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.

5. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

6. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

7. Should Customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will not be obligated hereunder to provide standby quantities for purposes of supplying such Customer requirements.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

LG&E Firm Transportation Service (Transportation Only) Rate FT is now contained on eleven pages instead of the current nine pages.

Standard Rate **FT**

Firm Transportation Service (Transportation Only)

SPECIAL TERMS AND CONDITIONS (continued) T

8. Company shall not be required to render service under this rate schedule to any Customer that fails to comply with any and all of the terms and conditions of this rate schedule.

TERMS AND CONDITIONS

Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 35
Canceling P.S.C. Gas No. 9, Original Sheet No. 35

Standard Rate **DGGS**
Distributed Generation Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to customer-owned electric generation facilities except (i) when such natural gas is limited to the production of electricity for Customer's own use during emergency situations during which Customer's normal supply of electricity is not otherwise available, and (ii) when such electric generation facilities have a total connected load of less than 2,000 cubic feet per hour. Natural gas purchased for electric generation facilities with a total connected load of 2,000 or more cubic feet per hour, or purchased to generate electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electrical supplies during emergency situations shall be subject to this tariff. Additionally, service under this Standard Rate DGGS shall be applicable only to electric generation facilities described above and installed and operating on and after ninety (90) days after August 1, 2010, (and therefore not eligible for service under Standard Rates CGS or IGS) by commercial and industrial customers.

Service hereunder shall be at a single delivery (custody transfer) point and where distribution mains are adjacent to the premises to be served. Gas sales service provided hereunder shall be metered and billed separately from gas service provided under any other rate schedule.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

Sales service hereunder shall be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other customers. Company may decline to accept customers under this rate schedule with a connected load of more than 8,000 cubic feet per hour. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this rate schedule.

If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, such residential customer shall be served under Rate DGGS.

CHARACTER OF SERVICE

Gas sales service under this rate schedule shall be considered firm.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 35

Standard Rate **DGGS**
Distributed Generation Gas Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to firm natural gas sales service to customer-owned electric generation facilities except (i) when such natural gas is limited to the production of electricity for Customer's own use during emergency situations during which Customer's normal supply of electricity is not otherwise available, and (ii) when such electric generation facilities have a total connected load of less than 2,000 cubic feet per hour. Natural gas purchased for electric generation facilities with a total connected load of 2,000 or more cubic feet per hour, or purchased to generate electricity for further distribution, for sale in the open market, or for any purpose other than to provide Customer with standby electrical supplies during emergency situations shall be subject to this tariff. Additionally, service under this Standard Rate DGGS shall be applicable only to electric generation facilities described above and installed and operating on and after ninety (90) days after August 1, 2010, (and therefore not eligible for service under Standard Rates CGS or IGS) by commercial and industrial customers.

Service hereunder shall be at a single delivery (custody transfer) point and where distribution mains are adjacent to the premises to be served. Gas sales service provided hereunder shall be metered and billed separately from gas service provided under any other rate schedule.

Service to Customer at multiple delivery points for the purpose of avoiding the threshold of 2,000 cubic feet per hour under Rate DGGS shall not be permitted.

Sales service hereunder shall be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's gas system to perform such service without detriment to its other customers. Company may decline to accept customers under this rate schedule with a connected load of more than 8,000 cubic feet per hour. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this rate schedule.

If an additional separate point of delivery is requested by a residential customer to provide gas for use in standby electric generation, such residential customer shall be served under Rate DGGS.

CHARACTER OF SERVICE

Gas sales service under this rate schedule shall be considered firm.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Ninth Revision of Original Sheet No. 35.1
Canceling P.S.C. Gas No. 9, Eighth Revision of Original Sheet No. 35.1

Standard Rate **DGGS**
Distributed Generation Gas Service

RATE

In addition to any other charges set forth herein, the following charges shall apply.

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 35.00 per delivery point per month
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$175.00 per delivery point per month

Demand Charge per 100 cubic feet of Monthly Billing Demand:	$1.1402
Plus a Charge Per 100 Cubic Feet:	
Distribution Cost Component	$0.03095
Gas Supply Cost Component	0.56128
Total Charge Per 100 Cubic Feet	$0.59223

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

The total monthly minimum bill shall be the sum of the minimum monthly Demand Charge and the Monthly Basic Service Charge.

In no case shall Company be obligated to deliver greater volumes hereunder than those specified in the written contract between Customer and Company. Payment of any and all charges hereunder shall not be considered an exclusive remedy for takes in excess of the maximum daily quantity ("MDQ"), nor shall the payment of such charges be considered a substitute for any other remedy (including, but not limited to, physical discontinuance or suspension of service hereunder) available to Company.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: October 28, 2014

DATE EFFECTIVE: November 1, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00348 dated October 27, 20014

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 35.1

Standard Rate **DGGS**
Distributed Generation Gas Service

RATE

In addition to any other charges set forth herein, the following charges shall apply.

Basic Service Charge:

If all of the customer's meters have a capacity < 5000 cf/hr:	$ 40.00 per delivery point per month	I
If any of the customer's meters have a capacity ≥ 5000 cf/hr:	$180.00 per delivery point per month	I

Demand Charge per 100 cubic feet of Monthly Billing Demand:	$1.1685	I
Plus a Charge Per 100 Cubic Feet:		
Distribution Cost Component	$0.03454	I
Gas Supply Cost Component	0.56128	
Total Charge Per 100 Cubic Feet	$0.59582	I

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet No. 85 of this Tariff. The Performance-Based Ratemaking Mechanism, set forth on Sheet No. 87, is included as a component of the Gas Supply Clause as shown on Sheet No. 85 of this Tariff.

The total monthly minimum bill shall be the sum of the minimum monthly Demand Charge and the Monthly Basic Service Charge.

In no case shall Company be obligated to deliver greater volumes hereunder than those specified in the written contract between Customer and Company. Payment of any and all charges hereunder shall not be considered an exclusive remedy for takes in excess of the maximum daily quantity ("MDQ"), nor shall the payment of such charges be considered a substitute for any other remedy (including, but not limited to, physical discontinuance or suspension of service hereunder) available to Company.

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Gas Line Tracker	Sheet No. 84
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Standard Rate **DGGS**
Distributed Generation Gas Service

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.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be sold by Company to Customer, and any other matters relating to individual customer circumstances.

2. The minimum contract term for service hereunder shall be for a period not less than five (5) years commencing from the effective date thereof.

3. Such written contract shall specify the minimum delivery pressure, the maximum hourly rate (“MHR”), and the maximum daily quantity (“MDQ”). The MHR is the maximum hourly gas load in 100 cubic feet that the Customer’s installation will require when operating at full capacity. The MDQ shall be twenty-four (24) times the MHR. The MDQ is the Monthly Billing Demand and shall not be less than 480 (four hundred and eighty) Ccf.

4. In no case shall Company be obligated to make deliveries hereunder at a pressure greater than thirty (30) psig, or the prevailing line pressure, whichever is less.

5. Increases in the MDQ may be requested annually by Customer. Customer may request Company to increase the MDQ at least ninety (90) days in advance of the anniversary date of the written contract. Such increases in the MDQ that are acceptable to Company in its sole discretion shall be effective on the anniversary date of the effective date of the written contract.

6. In the event that Company agrees to install any Company-owned facilities required to serve Customer, such facilities to be installed by Company shall be specified in the written contract and the cost of such facilities and installation thereof shall be paid by Customer to Company.

TERMS AND CONDITIONS

Service under this rate is subject to Company’s Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Standard Rate **DGGS**
Distributed Generation Gas Service

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.

SPECIAL TERMS AND CONDITIONS

1. Service under this rate schedule shall be performed under a written contract between Customer and Company setting forth specific arrangements as to the volumes to be sold by Company to Customer, and any other matters relating to individual customer circumstances.

2. The minimum contract term for service hereunder shall be for a period not less than five (5) years commencing from the effective date thereof.

3. Such written contract shall specify the minimum delivery pressure, the maximum hourly rate (“MHR”), and the maximum daily quantity (“MDQ”). The MHR is the maximum hourly gas load in 100 cubic feet that the Customer’s installation will require when operating at full capacity. The MDQ shall be twenty-four (24) times the MHR. The MDQ is the Monthly Billing Demand and shall not be less than 480 (four hundred and eighty) Ccf.

4. In no case shall Company be obligated to make deliveries hereunder at a pressure greater than thirty (30) psig, or the prevailing line pressure, whichever is less.

5. Increases in the MDQ may be requested annually by Customer. Customer may request Company to increase the MDQ at least ninety (90) days in advance of the anniversary date of the written contract. Such increases in the MDQ that are acceptable to Company in its sole discretion shall be effective on the anniversary date of the effective date of the written contract.

6. In the event that Company agrees to install any Company-owned facilities required to serve Customer, such facilities to be installed by Company shall be specified in the written contract and the cost of such facilities and installation thereof shall be paid by Customer to Company.

TERMS AND CONDITIONS

Service under this rate is subject to Company’s Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Second Revision of Original Sheet No. 45
Canceling P.S.C. Gas No. 9, First Revision of Original Sheet No. 45

Special Charges

The following charges will be applied uniformly throughout Company's service territory. Each charge, as approved by the Public Service Commission, reflects only that revenue required to cover associated expenses.

RETURNED PAYMENT CHARGE

In those instances where a Customer renders payment to Company which is not honored upon deposit by Company, the Customer will be charged $10.00 to cover the additional processing costs.

METER TEST CHARGE

Where the test of a meter is performed during normal working hours upon the written request of a Customer, pursuant to 807 KAR 5:006, Section 19, and the results show the meter is within the limits allowed by 807 KAR 5:022, Section 8(3)(a)1, and Section 8(3)(b)1, the Customer will be charged $90.00 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 gas service when discontinued for non-payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.

Customers under Gas Rates RGS, CGS and IGS may request and be granted temporary suspension of gas service. In the event of such temporary suspension, Company will make a charge of $28.00 to cover disconnection and reconnection of gas service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00.

INSPECTION CHARGE

With respect to Customer's service line and house line inspections prior to initiation or resumption of gas service, Company will make two such inspections without charge. When more than two trips are necessary to complete the inspections at any one location, a charge of $150.00 will be made for each additional trip.

CHARGE FOR TEMPORARY AND SHORT TERM SERVICE

The customer shall pay the cost of all material, labor and expense incurred by Company in supplying gas service for any temporary or short term use, in addition to the regular rates for service without pro-rating of rate blocks or minimum charges for service of less than thirty days in a regular meter reading period.

DATE OF ISSUE: April 22, 2013

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 45

Special Charges

The following charges will be applied uniformly throughout Company's service territory. Each charge, as approved by the Public Service Commission, reflects only that revenue required to cover associated expenses.

RETURNED PAYMENT CHARGE

In those instances where a Customer renders payment to Company which is not honored upon deposit by Company, the Customer will be charged $10.00 to cover the additional processing costs.

METER TEST CHARGE

Where the test of a meter is performed during normal working hours upon the written request of a Customer, pursuant to 807 KAR 5:006, Section 19, and the results show the meter is within the limits allowed by 807 KAR 5:022, Section 8(3)(a)1, and Section 8(3)(b)1, the Customer will be charged $90.00 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 gas service when discontinued for non-payment of bills or for violation of Company's Terms and Conditions, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $28.00. No charge will be made for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.

Customers under Gas Rates RGS, CGS, IGS, and AAGS may request and be granted T
temporary suspension of gas service In the event of such temporary suspension, Company will
make a charge of $28.00 to cover disconnection and reconnection of gas service, such charge
to be made before reconnection is effected. If both gas and electric services are reconnected
at the same time, the total charge for both services shall be $28.00. Customers taking service T
under Riders TS-2, GMPS, and EF shall not be eligible for such temporary suspension of T
service T

INSPECTION CHARGE

With respect to Customer's service line and house line inspections prior to initiation or resumption of gas service, Company will make two such inspections without charge. When more than two trips are necessary to complete the inspections at any one location, a charge of $150.00 will be made for each additional trip.

T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 45.1

Special Charges

ADDITIONAL TRIP CHARGE

Under Rate FT, Rider TS-2, and Rider GMPS, if the Company is required to make additional visits to the meter site due to the Company's inability to gain access to the meter location, or the necessary Communication Link (such as electric and telephone service) has not been properly installed by Customer, or the Customer's Communication Link is not working properly, the Company may charge the Customer for any additional trip to the site at a per-visit rate of $150.00.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 45.1

Special Charges

CHARGE FOR TEMPORARY AND SHORT TERM SERVICE T

The customer shall pay the cost of all material, labor and expense incurred by Company in supplying gas service for any temporary or short term use, in addition to the regular rates for service without pro-rating of rate blocks or minimum charges for service of less than thirty days in a regular meter reading period.

ADDITIONAL TRIP CHARGE

Under Rate FT, Rider TS-2, and Rider GMPS, if the Company is required to make additional visits to the meter site due to the Company's inability to gain access to the meter location, or the necessary Communication Link (such as electric and telephone service) has not been properly installed by Customer, or the Customer's Communication Link is not working properly, the Company may charge the Customer for any additional trip to the site at a per-visit rate of $150.00.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Ninth Revision of Original Sheet No. 50
Canceling P.S.C. Gas No. 9, Eighth Revision of Original Sheet No. 50

Standard Rate Rider **TS**
Gas Transportation Service/Standby

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to commercial and industrial customers served under Rate CGS and Rate IGS who consume either (a) an average of at least 50 Mcf each day during the billing cycle at each individual Delivery Point, or (b) 50,000 Mcf annually at each individual Delivery Point. Also available to customers served under Rate AAGS who consume at least 50 Mcf each day during the billing cycle at each individual Delivery Point. Customer shall have purchased natural gas elsewhere, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. Any transportation service hereunder will be conditioned on Company being able to retain or secure adequate standby quantities of natural gas. In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Rider TS shall continue to be effective for customers who have previously elected to transport under Rider TS as of the effective date hereof. However, service hereunder shall terminate on October 31, 2013, at which point Rider TS shall no longer be in effect.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $400.00 per Delivery Point per month

	CGS	IGS	AAGS
Distribution Charge Per Mcf	$2.0999	$2.1452	$0.6086
Pipeline Supplier's Demand Component	0.7792	0.7792	0.7792
Total	$2.8791	$2.9244	$1.3878

The **"Distribution Charge"** applicable to Rate CGS and IGS monthly quantities in excess of 100 Mcf shall be reduced by $0.50 per Mcf during the seven off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component: Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's Gas Supply Clause.

DATE OF ISSUE: October 28, 2014

DATE EFFECTIVE: November 1, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00348 dated October 27, 2014

The current LG&E Gas Transportation Service/Standby Rider TS terminated on October 31, 2013 and is being removed. Customers are being served under LG&E's current Gas Transportation Service/Firm Balancing Service Rider TS-2.

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 50.1
Canceling P.S.C. Gas No. 9, Original Sheet No. 50.1

Standard Rate Rider **TS**
Gas Transportation Service/Standby

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

IMBALANCES

Company will calculate on a monthly basis the Customer's imbalance resulting from the difference between the metered usage of the Customer and the volumes that the Customer has delivered into Company's system. This will be calculated as follows:

Imbalance = Metered Usage - Delivered Volumes

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volumes}}$$

CASH-OUT PROVISION FOR POSITIVE MONTHLY IMBALANCES (STANDBY SERVICE)

Company will provide standby quantities of natural gas hereunder for purposes of supplying Customer's requirements should Customer be unable to obtain sufficient transportation volumes. Such standby service will be provided at the same rates and under the same terms and conditions as those set forth in Company's applicable rate schedule under which it sells gas to Customer.

CASH-OUT PROVISION FOR NEGATIVE MONTHLY IMBALANCES

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lowest daily mid-point price posted in "*Platts Gas Daily"* for Dominion South Point during the month in which the negative imbalance occurred. The appropriate percentage shall be dependent on the Customer's monthly negative imbalance percentage to be applied as follows:

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

The current LG&E Gas Transportation Service/Standby Rider TS terminated on October 31, 2013 and is being removed. Customers are being served under LG&E's current Gas Transportation Service/Firm Balancing Service Rider TS-2.

CASH-OUT PROVISION FOR NEGATIVE MONTHLY IMBALANCES (continued)

When Total Net Negative Balance Percentage is:	The following percentage shall be multiplied by the above referenced "*Platts Gas Daily*" price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for negative imbalances that fall within each category. For example, a Customer with a negative monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the Customer's bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rate schedule.

Variations in MMBtu Content:
Changes in billings of the "cash-out" provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

SPECIAL TERMS AND CONDITIONS

1. Service under this rider shall be performed under a written contract between Customer and Company setting forth specific arrangements as to volumes to be transported by Company for Customer, points of delivery, methods of metering, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

2. At least ten days prior to the beginning of each month, Customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for Customer's account. Customer shall give Company at least twenty-four (24) hours' prior notice of any subsequent changes to scheduled deliveries.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

The current LG&E Gas Transportation Service/Standby Rider TS terminated on October 31, 2013 and is being removed. Customers are being served under LG&E's current Gas Transportation Service/Firm Balancing Service Rider TS-2.

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 50.3
Canceling P.S.C. Gas No. 9, Original Sheet No. 50.3

Standard Rate Rider **TS**
Gas Transportation Service/Standby

SPECIAL TERMS AND CONDITIONS (continued)

3. In no case will Company be obligated to supply gas to Customer, including both gas sold to Customer and gas transported hereunder, at greater volumes and greater rates of flow than those historically purchased by Customer from Company.

4. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.

5. All volumes of natural gas transported hereunder shall be of the same quality and meet the same specifications as that delivered to Company by its pipeline transporter.

6. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

7. Should Customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will provide standby quantities of natural gas to Customer as set forth in Customer's standard rate schedule CGS, IGS, or AAGS. In the event of an interruption of sales service to a Customer served under Rate AAGS, as provided for in that rate schedule, Company shall continue to deliver quantities of customer-owned natural gas in amounts equal to such quantities being delivered by pipeline transporter for Customer. During such periods of interruption, a Customer served under Rate AAGS shall not take quantities of natural gas in excess of those being delivered to Company on Customer's behalf. If Customer takes natural gas in excess of such quantities, Customer shall be subject to penalties in accordance with Company's Curtailment Rules.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

The current LG&E Gas Transportation Service/Standby Rider TS terminated on October 31, 2013 and is being removed. Customers are being served under LG&E's current Gas Transportation Service/Firm Balancing Service Rider TS-2.

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 51
Canceling P.S.C. Gas No. 9, Original Sheet No. 51

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to existing commercial and industrial customers served under Rates AAGS, CGS, and IGS who consume at least 15,000 Mcf annually at each individual Delivery Point during the two (2) years ending with the March 31 service request date.

This rider is available for qualified customers electing to transport under Rider TS-2 beginning November 1, 2013.

Customers electing service under this rider shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rider shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30.

For new customers whose historical gas consumption is not available, Company will determine Customer's eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Customer shall have purchased natural gas elsewhere, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization

In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Service under this rider shall not be available to Customers with a Maximum Daily Quantity ("MDQ") in excess of 5,000 Mcf/day. In the event that Customer's MDQ exceeds 5,000 Mcf/day, Company may terminate service under this rider upon thirty (30) days prior written notice. Additionally, Customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer's MDQ, are not eligible for service under this rider.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 51

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to existing commercial and industrial customers served under Rates AAGS, CGS, and IGS who consume at least 15,000 Mcf annually at each individual Delivery Point during the two (2) years ending with the March 31 service request date.

Customers electing service under this rider shall notify Company on or before March 31 and execute a contract by April 30 in order to receive service hereunder beginning November 1 of that same year. The Contract Year shall include the twelve monthly billing periods from November 1 through October 31, of the following calendar year. Service under this rider shall be for a term of one (1) year and year to year thereafter. Unless otherwise permitted herein, Customer or Company may terminate service hereunder effective November 1 by giving written notice to the other by the preceding April 30. T

For new customers whose historical gas consumption is not available, Company will determine Customer's eligibility for service hereunder based upon data provided by Customer and such other information as may be available to Company. Company may allow such new customers to begin service hereunder prior to the November 1 date specified above for existing customers.

Customer shall have purchased natural gas elsewhere, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization

In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the availability of adequate capacity on Company's system to perform such service without detriment to its other customers.

Service under this rider shall not be available to Customers with a Maximum Daily Quantity ("MDQ") in excess of 5,000 Mcf/day. In the event that Customer's MDQ exceeds 5,000 Mcf/day, Company may terminate service under this rider upon thirty (30) days prior written notice. Additionally, Customers using gas to generate electricity for use other than as standby electric service, irrespective of the size of the Customer's MDQ, are not eligible for service under this rider.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Ninth Revision of Original Sheet No. 51.1
Canceling P.S.C. Gas No. 9, Eighth Revision of Original Sheet No. 51.1

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

CHARACTER OF SERVICE

Transportation service under this rider shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter ("Receipt Point") to the Delivery Point at the Customer's place of utilization ("Delivery Point"), subject to paragraph 6 of the Special Terms and Conditions.

Due to the physical configuration of Company's system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company will provide service to meet imbalances on a firm basis. For purposes used herein, "Imbalances" are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point.

Customers served under this rider must designate a third-party TS-2 Pool Manager and become a member of a TS-2 Pool pursuant to Rider PS-TS-2.

Company shall issue an Action Alert as set forth in Rider PS-TS-2 when, in Company's sole discretion, such Action Alert is required to manage loads served under Rider TS-2. It is the responsibility of the TS-2 Pool Manager, not Company, to convey Action Alerts to Customers in the TS-2 Pool.

Any imbalances (over- or under-deliveries) incurred by TS-2 Pool Manager on behalf of Customer shall be resolved through the application of the cash-out mechanism incorporated in Rider PS-TS-2.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $400.00 per Delivery Point per month

	CGS	IGS	AAGS
Distribution Charge Per Mcf	$2.0999	$2.1452	$0.6086
Pipeline Supplier's Demand Component	0.7792	0.7792	0.7792
Total	$2.8791	$2.9244	$1.3878

DATE OF ISSUE: October 28, 2014

DATE EFFECTIVE: November 1, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00348 dated October 27, 2014

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 51.1

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

CHARACTER OF SERVICE

Transportation service under this rider shall be considered firm from the Receipt Point at Company's interconnection with its Pipeline Transporter ("Receipt Point") to the Delivery Point at the Customer's place of utilization ("Delivery Point"), subject to paragraph 6 of the Special Terms and Conditions.

Due to the physical configuration of Company's system, and in order to maintain system integrity and reliability, unless otherwise permitted or directed by Company in its sole discretion, the Pipeline Transporter shall be Texas Gas Transmission, LLC.

Company will provide service to meet imbalances on a firm basis. For purposes used herein, "Imbalances" are defined as the difference between the volume of gas delivered by the Customer to the Receipt Point and the volume of gas taken by Customer at the Delivery Point.

Customers served under this rider must designate a third-party TS-2 Pool Manager and become a member of a TS-2 Pool pursuant to Rider PS-TS-2.

Company shall issue an Action Alert as set forth in Rider PS-TS-2 when, in Company's sole discretion, such Action Alert is required to manage loads served under Rider TS-2. It is the responsibility of the TS-2 Pool Manager, not Company, to convey Action Alerts to Customers in the TS-2 Pool.

Any imbalances (over- or under-deliveries) incurred by TS-2 Pool Manager on behalf of Customer shall be resolved through the application of the cash-out mechanism incorporated in Rider PS-TS-2.

RATE

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $550.00 per Delivery Point per month I

	CGS	IGS	AAGS	
Distribution Charge Per Mcf	$2.3445	$2.4305	$0.8285	I
Pipeline Supplier's Demand Component	0.7792	0.7792	0.7792	
Total	$3.1237	$3.2097	$1.6077	I

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Ninth Revision of Original Sheet No. 51.2
Canceling P.S.C. Gas No. 9, Eighth Revision of Original Sheet No. 51.2

Standard Rate Rider TS-2
Gas Transportation Service/Firm Balancing Service

RATE (continued)

The **"Distribution Charge"** applicable to Rate CGS and IGS monthly quantities in excess of 100 Mcf shall be reduced by $0.50 per Mcf during the seven off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component: Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's Gas Supply Clause.

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder and not previously served under Rider TS. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rider TS-2. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rider TS-2 in order to recover from (or refund to) transferring sales customers any under- or over-collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause (“GSC”) applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company’s quarterly Gas Supply Clause filings.

For customers electing service under Rider TS-2 effective November 1, 2013, the Gas Cost True-Up Charge shall be:

$(0.0584) per Mcf for Bills Rendered On and After November 1, 2014

For customers electing service under Rider TS-2 effective November 1, 2014, the Gas Cost True-Up Charge shall be:

$0.5669 per Mcf for Bills Rendered On and After November 1, 2014

Minimum Annual Threshold Requirement and Charge: When Customer’s annual usage falls below the Minimum Annual Threshold Requirement, Customer will be charged a Minimum Annual Threshold Charge equal to the difference between the Minimum Annual Threshold Requirement of 15,000 Mcf and the Customer’s actual consumption in Mcf during each Contract Year which difference shall be multiplied by the peak period Distribution Charge of the applicable sales rate schedule. Such Minimum Annual Threshold Charge shall be billed during the month following the close of the Contract Year in accordance with the following formula

Minimum Annual Threshold Charge =

(Minimum Annual Threshold minus Customer’s Annual Usage) times the Peak Period Distribution Charge

DATE OF ISSUE: October 28, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00348 dated October 27, 2014

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 51.2

Standard Rate Rider TS-2
Gas Transportation Service/Firm Balancing Service

RATE (continued)

The **"Distribution Charge"** applicable to Rate CGS and IGS monthly quantities in excess of 100 Mcf shall be reduced by $0.50 per Mcf during the seven off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component: Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's Gas Supply Clause.

Gas Cost True-Up Charge: The Gas Cost True-Up Charge is applicable only to a former sales Customer that has elected transportation service hereunder and not previously served under Rate FT. Such Customer shall pay this charge for the first eighteen billing periods that Customer is served under Rider TS-2. The charge (or credit) per Mcf shall be applied to all volumes delivered by Company pursuant to Rider TS-2 in order to recover from (or refund to) transferring sales customers any under- or over-collected gas costs as reflected in the GCAA, GCBA, and PBRRC components of the Gas Supply Clause (“GSC”) applicable to gas sold during those periods when the transferring customer was a sales customer. The Gas Cost True-Up Charge amount shall be revised with each of Company’s quarterly Gas Supply Clause filings. T

For customers electing service under Rider TS-2 effective November 1, 2013, the Gas Cost True-Up Charge shall be:

$(0.0584) per Mcf for Bills Rendered On and After November 1, 2014

For customers electing service under Rider TS-2 effective November 1, 2014, the Gas Cost True-Up Charge shall be:

$0.5669 per Mcf for Bills Rendered On and After November 1, 2014

Minimum Annual Threshold Requirement and Charge: When Customer’s annual usage falls below the Minimum Annual Threshold Requirement, Customer will be charged a Minimum Annual Threshold Charge equal to the difference between the Minimum Annual Threshold Requirement of 15,000 Mcf and the Customer’s actual consumption in Mcf during each Contract Year which difference shall be multiplied by the peak period Distribution Charge of the applicable sales rate schedule. Such Minimum Annual Threshold Charge shall be billed during the month following the close of the Contract Year in accordance with the following formula

Minimum Annual Threshold Charge =

(Minimum Annual Threshold minus Customer’s Annual Usage) times the Peak Period Distribution Charge

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 51.3
Canceling P.S.C. Gas No. 9, Original Sheet No. 51.3

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

RATE (continued)

Such amount shall be applied to Customer's November bill.

Payment of the Minimum Annual Threshold Charge is not a remedy for Customer's failure to meet the Minimum Annual Threshold Requirement for service under Rider TS-2. In the event that Customer does not meet the Minimum Annual Threshold Requirement for two (2) consecutive years (as determined for the 12 months ended October), service to Customer under this rider may be discontinued. Customer and its TS-2 Pool Manager will receive notice by December 1 that Customer will be removed from the TS-2 Pool and returned to firm sales service effective April 1 of the following year.

New customers qualifying for service hereunder and who begin service prior to the November 1 date specified above shall not be subject to any Minimum Annual Threshold Charge for service prior to the November 1 date immediately following the commencement of service hereunder.

Optional Monthly Telemetry Charge: $300.00 per Delivery Point per month

ADJUSTMENT CLAUSES

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Demand Side Management Cost Recovery Mechanism	Sheet No. 86
Franchise Fee and Local Tax	Sheet No. 90
School Tax	Sheet No. 91

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rider. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

At the time that the Customer executes a contract for service hereunder, Customer shall elect to either (1) pay for the cost of this remote metering equipment and the cost of its installation (including any required meter replacement) in an up-front lump sum payment, or (2) pay the Optional Monthly Telemetry Charge specified herein.

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 51.3

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

RATE (continued)

Such amount shall be applied to Customer's November bill.

Payment of the Minimum Annual Threshold Charge is not a remedy for Customer's failure to meet the Minimum Annual Threshold Requirement for service under Rider TS-2. In the event that Customer does not meet the Minimum Annual Threshold Requirement for two (2) consecutive years (as determined for the 12 months ended October), service to Customer under this rider may be discontinued. Customer and its TS-2 Pool Manager will receive notice by December 1 that Customer will be removed from the TS-2 Pool and returned to firm sales service effective April 1 of the following year.

New customers qualifying for service hereunder and who begin service prior to the November 1 date specified above shall not be subject to any Minimum Annual Threshold Charge for service prior to the November 1 date immediately following the commencement of service hereunder.

Optional Monthly Telemetry Charge: $300.00 per Delivery Point per month

T

REMOTE METERING

Remote metering service shall be required as a prerequisite to the Customer obtaining service under this rider. The remote metering devices will allow Company and Customer to monitor the Customer's usage on a daily basis and allow Company to bill the Customer.

At the time that the Customer executes a contract for service hereunder, Customer shall elect
to either (1) pay for the cost of this remote metering equipment and the cost of its installation in T
an up-front lump sum payment, or (2) pay the Optional Monthly Telemetry Charge specified
herein. Under either option, Customer shall reimburse Company for the cost of any T
modifications to Company facilities and the replacement of any existing meters required in T
order to facilitate the functioning of the remote metering. T

The Customer shall be responsible for making any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in order to facilitate the installation and operation of such remote metering.

The Customer shall be responsible for providing the necessary and adequate electric and T
telephone service to provide remote metering by October 1 of the year that Customer's service ↓
under Rider TS-2 becomes effective. Electric and telephone services installed for this
equipment shall conform to Company's specifications. The Customer shall be responsible for
maintaining the necessary and adequate electric and telephone service to provide remote
metering.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 51.4
Canceling P.S.C. Gas No. 9, Original Sheet No. 51.4

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

REMOTE METERING (continued)

The Customer shall be responsible for providing the necessary and adequate electric and telephone service to provide remote metering by October 1 of the year that Customer's service under Rider TS-2 becomes effective. Electric and telephone services installed for this equipment shall conform to Company's specifications. The Customer shall be responsible for maintaining the necessary and adequate electric and telephone service to provide remote metering.

SPECIAL TERMS AND CONDITIONS

1. Service under this rider shall be performed under a written contract between Customer and Company setting forth specific arrangements as to volumes to be transported by Company for Customer, TS-2 Pool Manager designated by Customer, points of delivery, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

   Customer may appoint only one TS-2 Pool Manager for a given period. If Customer elects to change its TS-2 Pool Manager, Customer shall notify Company and execute and return the required documentation of its election to change its TS-2 Pool Manager at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective. Except as provided for in rider TS-2, no customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year. In appointing a TS-2 Pool Manager, Customer acknowledges that it has appointed the designated TS-2 Pool Manager to act as its limited agent in the performance of certain stated functions and to assume certain stated responsibilities with regard to transportation under Rider TS-2, including the requesting and receiving of information, the scheduling of gas flows, and all related duties. Customer will continue to be responsible for any and all costs, fees, and other liabilities as the result of the actions or inactions of TS-2 Pool Manager as its limited agent. Customer shall indemnify, defend, and hold Company harmless from any costs (including, but not limited to, reasonable attorney fees), expenses, losses, or liabilities, incurred (a) as a result of Company's performance when relying upon the authority of the TS-2 Pool Manager, (b) as a result of Company's reliance upon Customer's representation that it has express authority to appoint said TS-2 Pool Manager as its limited agent, and (c) due to the Customer's or TS-2 Pool Manager's failure to strictly comply with the provisions of Rider TS-2 or Rider PS-TS-2.

2. In no case will Company be obligated to deliver gas to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 51.4

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

SPECIAL TERMS AND CONDITIONS T

1. Service under this rider shall be performed under a written contract between Customer and Company setting forth specific arrangements as to volumes to be transported by Company for Customer, TS-2 Pool Manager designated by Customer, points of delivery, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

   Customer may appoint only one TS-2 Pool Manager for a given period. If Customer elects to change its TS-2 Pool Manager, Customer shall notify Company and execute and return the required documentation of its election to change its TS-2 Pool Manager at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective. Except as provided for in Rider TS-2, no customer may transfer from one TS-2 T
Pool to another more frequently than once during a Contract Year. In appointing a TS-2 Pool Manager, Customer acknowledges that it has appointed the designated TS-2 Pool Manager to act as its limited agent in the performance of certain stated functions and to assume certain stated responsibilities with regard to transportation under Rider TS-2, including the requesting and receiving of information, the scheduling of gas flows, and all related duties. Customer will continue to be responsible for any and all costs, fees, and other liabilities as the result of the actions or inactions of TS-2 Pool Manager as its limited agent. Customer shall indemnify, defend, and hold Company harmless from any costs (including, but not limited to, reasonable attorney fees), expenses, losses, or liabilities, incurred (a) as a result of Company's performance when relying upon the authority of the TS-2 Pool Manager, (b) as a result of Company's reliance upon Customer's representation that it has express authority to appoint said TS-2 Pool Manager as its limited agent, and (c) due to the Customer's or TS-2 Pool Manager's failure to strictly comply with the provisions of Rider TS-2 or Rider PS-TS-2.

2. In no case will Company be obligated to deliver gas to Customer in greater volumes or at greater rates of flow than those specified in the written contract between Customer and Company. The maximum daily volume that Company shall be obligated to deliver shall be referred to as the Maximum Daily Quantity ("MDQ"). The MDQ is the maximum daily T
volume of gas, as determined by Company, based on Customer's historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine Customer's MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 51.5

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

SPECIAL TERMS AND CONDITIONS (continued)

referred to as the Maximum Daily Quantity ("MDQ"). The MDQ is the maximum daily volume of gas, as determined by Company, based on Customer's historical daily metered volumes. In the event that historical daily metered volumes are not available, Company will determine Customer's MDQ based upon data provided by Customer and/or monthly metered data. Once historical daily metered data becomes available, the MDQ will be subject to revision by Company on an annual basis.

3. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.

4. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

5. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

6. In the event of an interruption of service to a Customer served under Rate AAGS, as provided for in that rate schedule, Customer shall discontinue the use of natural gas as specified therein, be subject to the penalties set forth therein, and discontinue deliveries of natural gas hereunder.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 51.5

Standard Rate Rider **TS-2**
Gas Transportation Service/Firm Balancing Service

SPECIAL TERMS AND CONDITIONS (continued)

T

3. Volumes of gas transported hereunder will be determined in accordance with Company's measurement base as set forth in the Terms and Conditions of this Tariff.

4. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

5. Company will have the right to curtail or interrupt the transportation or delivery of gas to any Customer hereunder when, in Company's judgment, such curtailment is necessary to enable Company to respond to an emergency or force majeure condition.

6. In the event of an interruption of service to a Customer served under Rate AAGS, as provided for in that rate schedule, Customer shall discontinue the use of natural gas as specified therein, be subject to the penalties set forth therein, and discontinue deliveries of natural gas hereunder.

TERMS AND CONDITIONS

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 52
Canceling P.S.C. Gas No. 9, Original Sheet No. 52

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to all commercial and industrial customers that request the Company to install a gas meter pulse generator which is a meter-related service not otherwise provided by the Company. This service is only available for customer metering sites using positive displacement meters, orifice meters, or ultrasonic metering technology, so long as the meter capacity is 3,000 cubic feet per hour or greater..

CHARACTER OF SERVICE

The service provided hereunder is a pulse generator (dry electrical contact closure) suitable for generating electrical pulses.

For customers not served under Rate Schedule FT or Rider TS-2, a separate pulse generator will be provided for each gas meter installed at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors may need to be applied by the Customer.

For customers served under Rate Schedule FT or Rider TS-2, a separate pulse generator will be totalized for gas meters at the customer's metering site. Each contact closure cycle on a pulse generator represents a pre-determined natural gas volume. The volume will vary at different meter installations, and will thus be communicated to the Customer at the time of installation. Pressure and temperature correcting factors are applied to the volumes provided and need not be applied by the Customer.

The Customer shall be responsible for providing and maintaining the necessary and adequate electric and telephone service ("Communication Links") per the Company's specifications.

The Company will provide the pulse generator(s). Customer Installed Equipment is any equipment or wiring installed by the Customer, or someone other than Company acting on behalf of Customer, and could include, but would not be limited to, any device such as a data concentrator, totalizer, programmable logic controller, remote terminal unit, or similar equipment used for the purpose of collecting the pulse data. Customer is responsible for installation of wiring to the pulse generator(s) and is responsible for providing the wetting voltage necessary to generate electrical pulses, as well as all dielectric isolation fittings, surge protection and electrical barriers. The wetting voltage must be a regulated DC voltage of 30 volts or less and

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 52

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to all commercial and industrial customers that request the Company to install a gas meter pulse generator which is a meter-related service not otherwise provided by the Company. This service is only available for customer metering sites using positive displacement meters, orifice meters, or ultrasonic metering technology, so long as the meter capacity is 3,000 cubic feet per hour or greater..

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P.S.C. Gas No. 9, First Revision of Original Sheet No. 52.1
Canceling P.S.C. Gas No. 9, Original Sheet No. 52.1

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

CHARACTER OF SERVICE (continued)

10 mA or less, or as otherwise determined by the Company. If Customer Installed Equipment is located within fifteen (15) feet of any gas pipeline flanges, gas regulators, or gas pressure relief devices; or if gas meters are installed in an enclosed space, then Customer Installed Equipment must be installed in accordance with National Electrical Code Class 1 Division 2 requirements.

A failure of the pulse generator will not be detected by Company on any routine meter reading nor necessarily during other operations. Therefore, Customer is required to recognize and report any problems with the pulse generator.

RATE

In addition to any other charges set forth herein, the following charges shall apply.

For Customers Served Under Rate Schedule FT or Rider TS-2:
Monthly Charge: $ 7.17

For Customers Not Served Under Rate Schedule FT or Rider TS-2:
Monthly Charge: $24.34

If replacement of the Gas Meter(s) is necessary for the installation of a pulse generator, then Customer shall be responsible for the actual meter and meter installation cost of such Gas Meter(s). Customer shall be responsible for making at its cost any necessary modifications to its facilities, including, but not limited to, any modifications of Customer's piping, in the event a replacement Gas Meter is necessary or as otherwise required by Company to facilitate this service.

SPECIAL TERMS AND CONDITIONS

1. All Customer Installed Equipment shall be owned, maintained and operated by Customer at its sole cost, including the installation thereof. Dielectric isolation fittings, surge protection and electrical barriers will be used by Customer at Customer's cost when connecting to Company's meter facilities. There may be instances where Company determines, in its sole discretion, that dielectric isolation fittings are not necessary. If such fittings are not determined to be necessary, Company shall notify the Customer in writing. All connections of Customer Installed Equipment to Company facilities and equipment will be made by Company or witnessed by Company's representatives. If applicable, all of Customer's Installed Equipment must be installed within fifty feet of Company's metering telemetry equipment. The Company has the right to inspect Customer's installed equipment, prior to initiating the pulse out service, but has no obligation to do so, and in conducting any inspection the Company is not undertaking or accepting any obligation, responsibility or duty whatsoever with regard to Customer Installed Equipment.

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 52.1

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

CHARACTER OF SERVICE (continued)

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Louisville Gas and Electric Company

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Canceling P.S.C. Gas No. 9, Original Sheet No. 52.2

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

SPECIAL TERMS AND CONDITIONS (continued)

2. Customer agrees and understands that pulse data generated by service under this tariff shall not be used for purposes of billing by Company for natural gas volumes used by the Customer. Furthermore, Customer agrees and understands the pulse generator(s) supplied do not represent a rate of flow, but only a total volume, and should not be used for process control or other purposes.

3. Customer warrants that Customer will not use pulse data in a manner that could result in or create an unsafe condition of any kind or type should the data signal from Company's natural gas metering equipment be lost or inaccurate for any reason whatsoever. Customer further warrants that any installation, operation, maintenance, repair, replacement or removal of Customer Installed Equipment shall not interfere with Company's access to or operation and maintenance of its facilities or equipment.

4. Company shall not be required to restore any lost data signal. Company reserves the right to upgrade, change, alter or remove any portion or all of Company's facilities, discontinue the data signal or require removal or disconnection of Customer's Installed Equipment, for any reason and without liability to Customer, with prior written notice to Customer. Customer may report data loss or interruptions during normal working hours to the Company. If Customer fails to comply within the time set forth in Company's written request, Company shall have the right to immediately remove Customer Installed Equipment without liability to Customer, and Customer shall reimburse Company for the actual cost of removing said Equipment. All costs associated with responding to Customer's calls and problems relating to service hereunder (including but not limited to call-out, overtime and call-back) shall be paid by Customer upon receipt of Company's invoice.

5. Company makes no representation and provides no warranty or guarantee relating to the operation of, or accuracy or availability of, the data signal provided through Company's equipment. Data received is for informational purposes only, and Company shall not be liable for Customer's use of Company's equipment or data taken therefrom for any purpose.

6. Either party may terminate service under this Rate Schedule upon sixty (60) days prior written notice. Customer shall immediately disconnect and remove Customer's Installed Equipment upon termination, or shall request Company to do so at Customer's sole cost.

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 52.2

Standard Rate Rider **GMPS**
Gas Meter Pulse Service

SPECIAL TERMS AND CONDITIONS (continued)

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Standard Rate Rider **GMPS**
Gas Meter Pulse Service

SPECIAL TERMS AND CONDITIONS (continued)

7. Customer shall indemnify, defend and hold Company, its parents, affiliates and subsidiaries and their officers, directors, and employees harmless, to the extent allowed by law, from and against any and all claims, suits, causes of action, liabilities, losses, damages, penalties, fines, fees, assessments, costs and expenses (including attorney's fees and costs incurred in any action or proceeding between Company and Customer or Company and a third party) whatsoever for damages to property or injuries or death to persons (including but not limited to Company's and/or Customer's employees or contractors), arising directly or indirectly from the installation, operation, maintenance, repair, removal, or use of Customer Installed Equipment or involving any inaccurate pulse data or the reliance of Customer or any third party on any pulse data provided pursuant to service hereunder.

TERMS AND CONDITIONS

Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

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Standard Rate Rider **GMPS**
Gas Meter Pulse Service

SPECIAL TERMS AND CONDITIONS (continued)

7. Customer shall indemnify, defend and hold Company, its parents, affiliates and subsidiaries and their officers, directors, and employees harmless, to the extent allowed by law, from and against any and all claims, suits, causes of action, liabilities, losses, damages, penalties, fines, fees, assessments, costs and expenses (including attorney's fees and costs incurred in any action or proceeding between Company and Customer or Company and a third party) whatsoever for damages to property or injuries or death to persons (including but not limited to Company's and/or Customer's employees or contractors), arising directly or indirectly from the installation, operation, maintenance, repair, removal, or use of Customer Installed Equipment or involving any inaccurate pulse data or the reliance of Customer or any third party on any pulse data provided pursuant to service hereunder.

TERMS AND CONDITIONS

Service under this rate is subject to Company's Terms and Conditions governing the supply of gas service as incorporated in this Tariff, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 59

Standard Rate Rider **PS-TS-2**

Pooling Service – Rider-TS-2

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to TS-2 Pool Managers.

Service under this rider shall not be available for new pool managers until the November 1 following the effective date of this rider.

For the purpose of this rider, a “TS-2 Pool Manager” is defined as an entity which has been appointed by a customer or group of customers served under Rider TS-2 to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties. A customer served under Rider TS-2 must join a Rider PS-TS-2 pool managed by a third-party Pool Manager.

RATE

In addition to any charges billed directly to TS-2 Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rider TS-2, the following charge shall apply to the TS-2 Pool Manager:

PS-TS-2 Pool Administrative Charge: $75 per Customer in TS-2 Pool per month

Other: In the event that TS-2 Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then TS-2 Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

CHARACTER OF SERVICE

Service under this rider allows a TS-2 Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more transportation customers that comprise a PS-TS-2 Pool.

The TS-2 Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of the Customers in the TS-2 Pool.

The TS-2 Pool Manager must secure its own upstream capacity from Pipeline Transporter to meet the requirements of the Customers in the TS-2 Pool, up to the total Maximum Daily Quantity of the Customers who are in the TS-2 Pool.

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 59

Standard Rate Rider **PS-TS-2**

Pooling Service – Rider-TS-2

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to TS-2 Pool Managers.

Service under this rider shall not be available for new pool managers until the November 1 following the effective date of this rider.

For the purpose of this rider, a “TS-2 Pool Manager” is defined as an entity which has been appointed by a customer or group of customers served under Rider TS-2 to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties. A customer served under Rider TS-2 must join a Rider PS-TS-2 pool managed by a third-party Pool Manager.

RATE

In addition to any charges billed directly to TS-2 Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rider TS-2, the following charge shall apply to the TS-2 Pool Manager:

PS-TS-2 Pool Administrative Charge: $75 per Customer in TS-2 Pool per month

Other: In the event that TS-2 Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then TS-2 Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

CHARACTER OF SERVICE

Service under this rider allows a TS-2 Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more transportation customers that comprise a PS-TS-2 Pool.

The TS-2 Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of the Customers in the TS-2 Pool.

The TS-2 Pool Manager must secure its own upstream capacity from Pipeline Transporter to meet the requirements of the Customers in the TS-2 Pool, up to the total Maximum Daily Quantity of the Customers who are in the TS-2 Pool.

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Standard Rate Rider **PS-TS-2**

Pooling Service – Rider TS-2

ACTION ALERTS

Company shall have the right to issue an Action Alert (“AA”) which will require actions by the TS-2 Pool Manager to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. It is the responsibility of the Pool Manager, not Company, to convey an AA to Customers in its TS-2 Pool. Pool Manager shall be responsible for complying with the directives contained in the AA.

Notice of an AA shall be provided to TS-2 Pool Manager at least eighteen (18) hours prior to the beginning of the gas day for which the AA is in effect. TS-2 Pool Manager shall respond to an AA by adjusting its deliveries to Company's system as directed in the AA within the specified timeframe.

Upon issuance of an AA, Company will direct TS-2 Pool Manager to deliver to Company from 0% to 100% of the total MDQ of those Customers in the TS-2 Pool (the PMDQ as defined hereafter). Any volume delivered by TS-2 Pool Manager that differs (either more or less) from the volume specified in the AA shall be subject to an Action Alert Charge.

Company may, in its sole discretion, issue an AA to an individual Pool Manager taking service under Rider PS-TS-2 without issuing an AA to all Pool Managers taking service under Rider PS-TS-2.

The Action Alert Charge shall be equal to $5.00 plus the mid-point price posted in *Platts Gas Daily* for Dominion South Point per Mcf on the day for which the AA was violated, plus any other charges under this rider.

Company will not be required to provide service under this rider for any TS-2 Pool Manager that does not comply with the terms or conditions of an AA. Payment of Action Alert Charges hereunder shall not be considered an exclusive remedy for failure to comply with an AA, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

IMBALANCES

Company will calculate on a daily and monthly basis the TS-2 Pool Manager’s imbalance resulting from the difference between the metered usage of the Customers in the TS-2 Pool and the volumes that the TS-2 Pool Manager has delivered into Company's system for the Customers in the TS-2 Pool. This will be calculated as follows:

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Standard Rate Rider **PS-TS-2**

Pooling Service – Rider TS-2

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Upon issuance of an AA, Company will direct TS-2 Pool Manager to deliver to Company from 0% to 100% of the total MDQ of those Customers in the TS-2 Pool (the PMDQ as defined hereafter). Each Mcf delivered by TS-2 Pool Manager that differs (either more or less) from the volume specified in the AA shall be subject to an Action Alert Charge. T

Company may, in its sole discretion, issue an AA to an individual Pool Manager taking service under Rider PS-TS-2 without issuing an AA to all Pool Managers taking service under Rider PS-TS-2.

The Action Alert Charge per Mcf shall be equal to $5.00 plus the higher of the following: either (a) the daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS for the day on which the AA was violated, or (b) the daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS for the day on which the AA was violated. Such Action Alert Charge shall be in addition to any other charges under this rider. T

Company will not be required to provide service under this rider for any TS-2 Pool Manager that does not comply with the terms or conditions of an AA. Payment of Action Alert Charges hereunder shall not be considered an exclusive remedy for failure to comply with an AA, nor shall the payment of such charges be considered a substitute for any other remedy available to Company.

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State Regulation and Rates
Louisville, Kentucky

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

Imbalance = Metered Usage - Delivered Volumes

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volumes}}$$

The term “day” or “daily” shall mean the period of twenty-four (24) consecutive hours beginning at 10:00 a.m. Eastern Clock Time.

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

The cash-out provision shall be applied against the aggregate volume of all Customers in a specific TS-2 Pool. The TS-2 Pool Manager will be responsible for the payment of the cash-out charges incurred by the TS-2 Pool as a result of imbalances under Rider TS-2.

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from TS-2 Pool Manager at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lowest daily mid-point price posted in "*Platts Gas Daily"* for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly negative imbalance percentage to be applied as follows:

When Total Net Negative Balance Percentage is:	The following percentage shall be multiplied by the above referenced "*Platts Gas Daily"* price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	90%
>10% to ≤15%	80%
>15% to ≤20%	70%
>20%	60%

If the monthly imbalance is positive (an under-delivery into Company's system), TS-2 Pool Manager shall be billed for the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the highest daily mid-point price posted in "*Platts Gas Daily*" for Dominion South Point during the month in which the imbalance occurred. The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly imbalance percentage to be applied as follows:

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Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

IMBALANCES T

Company will calculate on a daily and monthly basis the TS-2 Pool Manager’s imbalance resulting from the difference between the metered usage of the Customers in the TS-2 Pool and the volumes that the TS-2 Pool Manager has delivered into Company's system for the Customers in the TS-2 Pool. This will be calculated as follows:

Imbalance = Metered Usage - Delivered Volumes

Company will also determine the imbalance percentage. This percentage will be calculated as follows:

$$\text{Imbalance \%} = \frac{\text{(Metered Usage - Delivered Volumes)}}{\text{Delivered Volumes}}$$

The term “day” or “daily” shall mean the period of time corresponding to the gas day as T
observed by the Pipeline Transporter as adjusted for local time. T

CASH-OUT PROVISION FOR MONTHLY IMBALANCES

The cash-out provision shall be applied against the aggregate volume of all Customers in a specific TS-2 Pool. The TS-2 Pool Manager will be responsible for the payment of the cash-out charges incurred by the TS-2 Pool as a result of imbalances under Rider TS-2.

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from TS-2 Pool Manager at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either T (a) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly negative imbalance percentage to be applied as follows:

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 59.3
Canceling P.S.C. Gas No. 9, Original Sheet No. 59.3

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

CASH-OUT PROVISION FOR MONTHLY IMBALANCES (continued)

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-referenced "*Platts Gas Daily*" price for Dominion South Point:
0% to ≤5%	100%
>5% to ≤10%	110%
>10% to ≤15%	120%
>15% to ≤20%	130%
>20%	140%

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a TS-2 Pool Manager with a negative monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the TS-2 Pool Manager's bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rider.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

NOMINATIONS AND NOMINATED VOLUME

As further described below, TS-2 Pool Manager shall specify to Company the daily volume of gas required by the Customers in the TS-2 Pool. Such volume shall be stated in Mcf/day and converted to MMBtu/day.

At least ten (10) days prior to the beginning of each calendar month, TS-2 Pool Manager shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for the Pool Manager's TS-2 Pool.

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 59.3

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

CASH-OUT PROVISION FOR MONTHLY IMBALANCES (continued)

When Total Net Negative Balance Percentage is:	The following percentage shall be multiplied by the above-determined amount:	
		T
0% to ≤5%	100%	
>5% to ≤10%	90%	
>10% to ≤15%	80%	
>15% to ≤20%	70%	
>20%	60%	

If the monthly imbalance is positive (an under-delivery into Company's system), TS-2 Pool Manager shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the month in which the imbalance occurred.

The appropriate percentage shall be dependent on the TS-2 Pool Manager's monthly imbalance percentage to be applied as follows:

When Total Net Positive Imbalance Percentage is:	The following percentage shall be multiplied by the above-determined amount:	
		T
0% to ≤5%	100%	
>5% to ≤10%	110%	
>10% to ≤15%	120%	
>15% to ≤20%	130%	
>20%	140%	
		T

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Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Third Revision of Original Sheet No. 59.4
Canceling P.S.C. Gas No. 9, Second Revision of Original Sheet No. 59.4

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

NOMINATIONS AND NOMINATED VOLUME (continued)

Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by TS-2 Pool Manager to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from TS-2 Pool Manager daily nominations or changes thereto that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company.

Such volumes nominated by TS-2 Pool Manager shall include an allowance for Company's system average lost and unaccounted for gas ("LAUFG") expressed as a percentage and based on historical levels. Effective November 1, 2014, such LAUFG percentage is 3.25%. Such LAUFG percentage shall be revised annually each November 1 with notice provided to TS-2 Pool Manager at least thirty (30) days prior to such November 1. The volumes delivered by the TS-2 Pool Manager to Company for redelivery to Customers in the TS-2 Pool will be increased by TS-2 Pool Manager to cover the effective LAUFG percentage. For example, if the Customers in a TS-2 Pool require 325 Mcf on a given day, and the LAUFG% is 5.0%, then the Mcf nominated shall be 342 Mcf [325 / (1 - 0.05)]. The 342 Mcf shall be converted to MMBtu using a standard conversion factor as may be specified by Company from time to time. Such amount does not include any retention by the Pipeline Transporter. The volume nominated by the TS-2 Pool Manager to cover LAUFG shall not be considered in determining whether or not the TS-2 Pool Manager has exceeded the Pool Maximum Daily Quantity ("PMDQ") for the TS-2 Pool.

SUPPLIER CODE OF CONDUCT

Each PS-TS-2 Pool Manager participating in the Company's transportation program under Rider PS-TS-2 must:

1. communicate to participating Customers in clear, understandable terms the Customer's rights and responsibilities. This communication must include (a) the PS-TS-2 Pool Manager's customer service address and local or toll-free telephone number; and (b) a statement describing the PS-TS-2 Pool Manager's dispute resolution procedures;

2. provide in writing pricing and payment terms that are clearly defined and understandable and that inform consumers whether the price that the Customer will pay is inclusive or exclusive of applicable taxes, and Company approved tariff riders and surcharges;

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 59.4

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

CASH-OUT PROVISION FOR MONTHLY IMBALANCES (continued) T

The monthly imbalance percentages stated above will be used to calculate the cash-out price for imbalances that fall within each category. For example, a TS-2 Pool Manager with a negative monthly imbalance percentage of 9% will cash-out at the 0% to 5% price for 5% of the imbalance and at the 5% to 10% price for 4% of the imbalance.

All such adjustments shall be shown and included on the TS-2 Pool Manager's bill. The billing of these charges shall not be construed as a waiver by Company of any other rights or remedies it has under law, the regulations of the PSC of Kentucky, or this rate schedule, nor shall it be construed as an exclusive remedy for failure to comply with the provisions of this rider.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

NOMINATIONS AND NOMINATED VOLUME

As further described below, TS-2 Pool Manager shall specify to Company the daily volume of gas required by the Customers in the TS-2 Pool. Such volume shall be stated in Mcf/day and converted to MMBtu/day.

At least ten (10) days prior to the beginning of each calendar month, TS-2 Pool Manager shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for the Pool Manager's TS-2 Pool.
Any changes in nominated volumes, as well as any other information required to effectuate the delivery of such gas to Company by the Pipeline Transporter, shall be provided by TS-2 Pool Manager to Company no later than 10:00 a.m. Eastern Clock Time on the day prior to the day(s) for which volumes are scheduled to flow. Only those volumes actually confirmed by Company and scheduled on the Pipeline Transporter are considered nominated volumes. Company shall not be obligated to accept from TS-2 Pool Manager daily nominations or changes thereto that are made after the daily deadline for such nominations as set forth above or that are made on weekend days or holidays as such are observed by Company.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

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Canceling P.S.C. Gas No. 9, Original Sheet No. 59.5

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

SUPPLIER CODE OF CONDUCT (continued)

3. refrain from engaging in communications or promotional practices which are fraudulent, deceptive, or misleading;

4. deliver gas to the Company on a firm basis on behalf of the Customers enrolled in the PS-TS-2 Pool Manager's pool in accordance with the requirements of the PS-TS-2 Pool Management Agreement;

5. establish and maintain a credit-worthy financial position that enables PS-TS-2 Pool Manager to indemnify the Company and the Customers for costs incurred as a result of any failure by the PS-TS-2 Pool Manager to deliver gas in accordance with the requirements of Rider PS-TS-2 and to assure payment of any applicable charges for any such failure;

6. refrain from requesting customer-specific billing, payment, and usage history without first having received the Customer's written approval allowing PS-TS-2 Pool Manager to access such information.

Failure to fulfill any of these obligations shall be considered a violation of the Supplier Code of Conduct.

If the PS-TS-2 Pool Manager fails to comply with the Supplier Code of Conduct, the Company will have the discretion to temporarily suspend or terminate such PS-TS-2 Pool Manager from further participation in the transportation program under Rider PS-TS-2. If service to the PS-TS-2 Pool Manager is suspended or terminated, Customer(s) in the PS-TS-2 Pool Manager's Pool will be returned to sales service under the applicable rate schedule (CGS, IGS, or AAGS) until said Customer(s) join another PS-TS-2 Pool Manager's Pool. If the Company seeks to suspend or terminate service to a PS-TS-2 Pool Manager, Company shall first notify the PS-TS-2 Pool Manager of the alleged violations which merit suspension or termination. Such notice must be in writing and must be sent to the PS-TS-2 Pool Manager as specified in the notice provisions of the PS-TS-2 Pool Management Agreement at least five (5) business days prior to the effective date of the suspension or termination.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in a TS-2 Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rider TS-2, and no Customer shall participate in more than one pool concurrently. Except as provided for in Section 4 below, no Customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year.

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State Regulation and Rates
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P.S.C. Gas No. 10, Original Sheet No. 59.5

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

NOMINATIONS AND NOMINATED VOLUME (continued) T

Such volumes nominated by TS-2 Pool Manager shall include an allowance for Company's system average lost and unaccounted for gas ("LAUFG") expressed as a percentage and based on historical levels. Effective November 1, 2013, such LAUFG percentage is 3.56%. Such LAUFG percentage shall be revised annually each November 1 with notice provided to TS-2 Pool Manager at least thirty (30) days prior to such November 1. The volumes delivered by the TS-2 Pool Manager to Company for redelivery to Customers in the TS-2 Pool will be increased by TS-2 Pool Manager to cover the effective LAUFG percentage. For example, if the Customers in a TS-2 Pool require 325 Mcf on a given day, and the LAUFG% is 5.0%, then the Mcf nominated shall be 342 Mcf [325 / (1 - 0.05)]. The 342 Mcf shall be converted to MMBtu using a standard conversion factor as may be specified by Company from time to time. Such amount does not include any retention by the Pipeline Transporter. The volume nominated by the TS-2 Pool Manager to cover LAUFG shall not be considered in determining whether or not the TS-2 Pool Manager has exceeded the Pool Maximum Daily Quantity ("PMDQ") for the TS-2 Pool.

SUPPLIER CODE OF CONDUCT

Each PS-TS-2 Pool Manager participating in the Company's transportation program under Rider PS-TS-2 must:

1. communicate to participating Customers in clear, understandable terms the Customer's rights and responsibilities. This communication must include (a) the PS-TS-2 Pool Manager's customer service address and local or toll-free telephone number; and (b) a statement describing the PS-TS-2 Pool Manager's dispute resolution procedures;

2. provide in writing pricing and payment terms that are clearly defined and understandable and that inform consumers whether the price that the Customer will pay is inclusive or exclusive of applicable taxes, and Company approved tariff riders and surcharges;

3. refrain from engaging in communications or promotional practices which are fraudulent, deceptive, or misleading; T

4. deliver gas to the Company on a firm basis on behalf of the Customers enrolled in the PS-TS-2 Pool Manager's pool in accordance with the requirements of the PS-TS-2 Pool Management Agreement;

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

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Canceling P.S.C. Gas No. 9, Original Sheet No. 59.6

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

SPECIAL TERMS AND CONDITIONS (continued)

2. To receive service hereunder, the PS-TS-2 Pool Manager shall enter into a PS-TS-2 Pool Management Agreement with Company. The PS-TS-2 Pool Management Agreement shall set forth the specific obligations of the TS-2 Pool Manager and Company under this rider.

   The TS-2 Pool Manager shall submit a signed PS-TS-2 Pool Management Agreement at least thirty (30) days prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the TS-2 Pool Manager of the date when service hereunder will commence. The Customers in the TS-2 Pool shall be set forth in Exhibit A of the PS-TS-2 Pool Management Agreement. In order to join a TS-2 Pool, Customer must have designated in writing its TS-2 Pool Manager as its agent pursuant to Rider TS-2. In order to modify the Customers in the pool, the Pool Manager must request a revised Exhibit A from Company and execute and return said exhibit at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective.

   The PMDQ shall be set forth in the Pool Management Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the TS-2 Pool. Company is not obligated to accept volumes for re-delivery on any day in excess of the PMDQ.

3. The TS-2 Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure TS-2 Pool Manager's performance of its obligations under the PS-TS-2 Pool Management Agreement. In determining the level of the bond or other security to be required of a TS-2 Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customers in the TS-2 Pool, the general creditworthiness of the TS-2 Pool Manager, and the TS-2 Pool Manager's prior credit record with Company, if any. In the event that the TS-2 Pool Manager defaults on its obligations under this rider or the PS-TS-2 Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy TS-2 Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-TS-2 Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The PS-TS-2 Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if a TS-2 Pool Manager fails to meet any condition of this rider and/or Rider TS-2. The PS-TS-2 Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the TS-2 Pool Manager has payments in arrears. Written notice of termination of the PS-TS-2 Pool Management Agreement shall be provided both to the TS-2 Pool Manager and to the individual Customers in the TS-2 Pool by Company.

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State Regulation and Rates
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P.S.C. Gas No. 10, Original Sheet No. 59.6

Standard Rate Rider **PS-TS-2**
Pooling Service – Rider TS-2

SUPPLIER CODE OF CONDUCT T

5. establish and maintain a credit-worthy financial position that enables PS-TS-2 Pool Manager to indemnify the Company and the Customers for costs incurred as a result of any failure by the PS-TS-2 Pool Manager to deliver gas in accordance with the requirements of Rider PS-TS-2 and to assure payment of any applicable charges for any such failure;
6. refrain from requesting customer-specific billing, payment, and usage history without first having received the Customer's written approval allowing PS-TS-2 Pool Manager to access such information.

Failure to fulfill any of these obligations shall be considered a violation of the Supplier Code of Conduct.

If the PS-TS-2 Pool Manager fails to comply with the Supplier Code of Conduct, the Company will have the discretion to temporarily suspend or terminate such PS-TS-2 Pool Manager from further participation in the transportation program under Rider PS-TS-2. If service to the PS-TS-2 Pool Manager is suspended or terminated, Customer(s) in the PS-TS-2 Pool Manager's Pool will be returned to sales service under the applicable rate schedule (CGS, IGS, or AAGS) until said Customer(s) join another PS-TS-2 Pool Manager's Pool. If the Company seeks to suspend or terminate service to a PS-TS-2 Pool Manager, Company shall first notify the PS-TS-2 Pool Manager of the alleged violations which merit suspension or termination. Such notice must be in writing and must be sent to the PS-TS-2 Pool Manager as specified in the notice provisions of the PS-TS-2 Pool Management Agreement at least five (5) business days prior to the effective date of the suspension or termination.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in a TS-2 Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rider TS-2, and no Customer shall participate in more than one pool concurrently. Except as provided for in Section 4 below, no Customer may transfer from one TS-2 Pool to another more frequently than once during a Contract Year.

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2. To receive service hereunder, the PS-TS-2 Pool Manager shall enter into a PS-TS-2 Pool Management Agreement with Company. The PS-TS-2 Pool Management Agreement shall set forth the specific obligations of the TS-2 Pool Manager and Company under this rider.

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State Regulation and Rates
Louisville, Kentucky

Standard Rate Rider **PS-TS-2**

Pooling Service – Rider TS-2

SPECIAL TERMS AND CONDITIONS (continued)

Customers in the TS-2 Pool will be returned to sales service under the applicable rate schedule (CGS, IGS, or AAGS), or will be allowed to enroll in another TS-2 Pool.

5. Company shall directly bill the TS-2 Pool Manager for the PS-TS-2 Pool Administrative Charge, Action Alert Charges, and cash-out charges or payments contained in Rider TS-2. The monthly bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty-seven (27) days from the date of the bill then the TS-2 Pool Manager will be considered in default.
6. Company shall directly bill the individual Customers in the TS-2 Pool for all Administrative Charges, Distribution Charges, Pipeline Supplier's Demand Component Charges, Gas Cost True-Up Charges, Basic Service Charges, Minimum Annual Threshold Charges, Monthly Telemetry Charges, and other remote metering charges, as provided for in either Rider TS-2 or Customer's otherwise applicable sales rate schedule to which Rider TS-2 is a rider.
7. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

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State Regulation and Rates
Louisville, Kentucky

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Standard Rate Rider **PS-TS-2**

Pooling Service – Rider TS-2

SPECIAL TERMS AND CONDITIONS (continued) T

The TS-2 Pool Manager shall submit a signed PS-TS-2 Pool Management Agreement at least thirty (30) days prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the TS-2 Pool Manager of the date when service hereunder will commence. The Customers in the TS-2 Pool shall be set forth in Exhibit A of the PS-TS-2 Pool Management Agreement. In order to join a TS-2 Pool, Customer must have designated in writing its TS-2 Pool Manager as its agent pursuant to Rider TS-2. In order to modify the Customers in the pool, the Pool Manager must request a revised Exhibit A from Company and execute and return said exhibit at least thirty (30) days prior to the beginning of the billing period for which the change is to become effective.

The PMDQ shall be set forth in the Pool Management Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the TS-2 Pool. Company is not obligated to accept volumes for re-delivery on any day in excess of the PMDQ.

3. The TS-2 Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure TS-2 Pool Manager's performance of its obligations under the PS-TS-2 Pool Management Agreement. In determining the level of the bond or other security to be required of a TS-2 Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customers in the TS-2 Pool, the general creditworthiness of the TS-2 Pool Manager, and the TS-2 Pool Manager's prior credit record with Company, if any. In the event that the TS-2 Pool Manager defaults on its obligations under this rider or the PS-TS-2 Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy TS-2 Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-TS-2 Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.
4. The PS-TS-2 Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if a TS-2 Pool Manager fails to meet any condition of this rider and/or Rider TS-2. The PS-TS-2 Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the TS-2 Pool Manager has payments in arrears. Written notice of termination of the PS-TS-2 Pool Management Agreement shall be provided both to the TS-2 Pool Manager and to the individual Customers in the TS-2 Pool by Company.

Customers in the TS-2 Pool will be returned to sales service under the applicable rate schedule (CGS, IGS, or AAGS), or will be allowed to enroll in another TS-2 Pool. T

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

LG&E Rider PS-TS-2, Pooling Service for Gas Transportation Service/Firm Balancing Service Rider TS-2 is now contained on nine pages instead of the current eight pages.

Standard Rate Rider **PS-TS-2**

Pooling Service – Rider TS-2

SPECIAL TERMS AND CONDITIONS (continued) T

5. Company shall directly bill the TS-2 Pool Manager for the PS-TS-2 Pool Administrative Charge, Action Alert Charges, and cash-out charges or payments contained in Rider TS-2. The monthly bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty-seven (27) days from the date of the bill then the TS-2 Pool Manager will be considered in default.

6. Company shall directly bill the individual Customers in the TS-2 Pool for all Administrative Charges, Distribution Charges, Pipeline Supplier's Demand Component Charges, Gas Cost True-Up Charges, Basic Service Charges, Minimum Annual Threshold Charges, Monthly Telemetry Charges, and other remote metering charges, as provided for in either Rider TS-2 or Customer's otherwise applicable sales rate schedule to which Rider TS-2 is a rider.

7. All volumes of natural gas received by Company for Customer shall meet the specifications established by Pipeline Transporter.

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State Regulation and Rates
Louisville, Kentucky

Standard Rate Rider **PS-TS**

Pooling Service – Rider TS

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to "TS Pool Managers".

Rider PS-TS shall continue to be effective for customers who have previously elected to transport under Rider TS as of the effective date hereof. However, service hereunder shall terminate on October 31, 2013, at which point Rider PS-TS shall no longer be in effect.

For the purpose of this rider a "TS Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rider TS to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties.

RATE

In addition to any charges billed directly to TS Pool Manager or Customer as a result of the application of Rider TS or this rider, the following charge shall apply:

PS-TS Pool Administrative Charge: $75 per customer in TS Pool per month

CHARACTER OF SERVICE

Service under this rider allows a TS Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more standby sales transportation customers that comprise a PS-TS Pool.

The TS Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of customer(s) in the pool. The Cash-Out Provision of Rider TS shall be applied against the aggregate volume of all customers in a specific pool. The TS Pool Manager will be responsible for the payment of the PS-TS Pool Administrative Charge and any Monthly Cash-Out payments incurred by a specific pool as a result of imbalances under Rider TS.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in a TS Pool that does not individually meet the availability conditions of Rider TS, and no customer shall participate in more than one pool concurrently. Likewise, customers served under As-Available Gas Service Rate AAGS cannot be in the same pool with customers served under other sales rates.

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The current LG&E Rider PS-TS, Pooling Service for Gas Transportation Service/Standby Rider TS is being removed, as Gas Transportation Rider TS terminated on October 31, 2013. Customers served under LG&E's current Gas Transportation Service/Firm Balancing Service Rider TS-2 will continue to be served under LG&E's Rider PS-TS-2.

Standard Rate Rider

PS-TS
Pooling Service – Rider TS

SPECIAL TERMS AND CONDITIONS (continued)

2. To receive service hereunder, the PS-TS Pool Manager shall enter into a PS-TS Pool Management Agreement with Company and shall submit a PS-TS Application/Agency Agreement for each member of the pool, signed by both Customer and its TS Pool Manager. The PS-TS Pool Management Agreement shall set forth the specific obligations of the TS Pool Manager and Company under this rider. The PS-TS Application/Agency Agreement shall set forth the members of the pool.

   The TS Pool Manager shall submit a signed PS-TS Pool Management Agreement and a PS-TS Application/Agency Agreement for each member of the pool at least four (4) weeks prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the TS Pool Manager of the date when service hereunder will commence. A customer who terminates service under this rider or who desires to change TS Pool Managers shall likewise provide Company with a written notice at least four (4) weeks prior to the end of a billing period.

3. The TS Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure TS Pool Manager's performance of its obligations under the PS-TS Pool Management Agreement. To the extent that TS Pool Manager maintains a cash deposit with Company, Company shall refund such amount to TS Pool Manager, and TS Pool Manager shall provide Company with a surety bond, an irrevocable letter of credit, or other financial instrument satisfactory to Company in the amount determined by Company and at the time that such amount is next re-determined by Company. In determining the level of the bond or other security to be required of a TS Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of PS-TS Pool members, the general credit worthiness of the TS Pool Manager, and the TS Pool Manager's prior credit record with Company, if any. In the event that the TS Pool Manager defaults on its obligations under this rider or the PS-TS Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy TS Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-TS Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The TS Pool Manager shall provide Company with the written consent, in the form of a PS-TS Application/Agency Agreement, of all members to any change in the composition of the pool membership at least four weeks prior to the beginning of the first billing period that would apply to the modified pool. With the consent of the current pool members, the TS Pool Manager may provide written consent in the form of a PS-TS Application/Agency Agreement on behalf of the current pool members to any change in the composition of the

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The current LG&E Rider PS-TS, Pooling Service for Gas Transportation Service/Standby Rider TS is being removed, as Gas Transportation Rider TS terminated on October 31, 2013. Customers served under LG&E's current Gas Transportation Service/Firm Balancing Service Rider TS-2 will continue to be served under LG&E's Rider PS-TS-2.

SPECIAL TERMS AND CONDITIONS (continued)

pool. Without exception, any new pool member must provide its own written consent in the form of a PS-TS Application/Agency Agreement.

5. The PS-TS Pool Management Agreement will be terminated by Company upon four weeks written notice if a TS Pool Manager fails to meet any condition of this rider and/or Rider TS. The PS-TS Pool Management Agreement will also be terminated by Company upon four weeks written notice if the TS Pool Manager has payments in arrears. Written notice of termination of the PS-TS Pool Management Agreement shall be provided both to the TS Pool Manager and to the individual members of the pool by Company.

6. Company shall directly bill the TS Pool Manager for the PS-TS Pool Administrative Charge, monthly cash-out charges or payments contained in Rider TS. The monthly bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty-seven (27) days from the date of the bill then the TS Pool Manager will be considered in default.

7. Company shall directly bill the individual customers in the pool for all Distribution Charges, Basic Service Charges, and Administrative Charges as provided for in either Rider TS or Customer's otherwise applicable sales rate schedule to which Rider TS is a Rider.

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The current LG&E Rider PS-TS, Pooling Service for Gas Transportation Service/Standby Rider TS is being removed, as Gas Transportation Rider TS terminated on October 31, 2013. Customers served under LG&E's current Gas Transportation Service/Firm Balancing Service Rider TS-2 will continue to be served under LG&E's Rider PS-TS-2.

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 61
Canceling P.S.C. Gas No. 9, Original Sheet No. 61

Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to "FT Pool Managers".

For the purpose of this rider, a "FT Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rate FT to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties.

RATE

In addition to any charges billed directly to FT Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rate FT, the following charge shall apply to FT Pool Manager:

PS-FT Pool Administrative Charge: $75 per Customer in FT Pool per month

Other: In the event that FT Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then FT Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

CHARACTER OF SERVICE

Service under this rider allows an FT Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more firm transportation customers that comprise a PS-FT Pool. Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT. It is the responsibility of the FT Pool Manager to convey OFOs to Customers in its FT Pool.

The FT Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of Customers in the FT Pool. The FT Pool Manager shall be subject to the same nomination deadlines as set forth in Rate FT. The Daily Utilization Charge, OFO Penalty and cash-out provision of Rate FT shall be applied against the aggregate volume of all Customers in a specific FT Pool. The FT Pool Manager will be responsible for the payment of the PS-FT Pool Administrative Charge and any Daily Utilization Charges, OFO penalties or monthly cash-out payments incurred by a specific FT Pool as a result of imbalances under Rate FT. For purposes of this rider the Daily Utilization Charge shall apply to

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 61

Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Available to "FT Pool Managers".

For the purpose of this rider, a "FT Pool Manager" is defined as an entity which has been appointed by a customer or group of customers served under Rate FT to perform the functions and responsibilities of requesting and receiving information, nominating supply, and other related duties.

RATE

In addition to any charges billed directly to FT Pool Manager as a result of the application of this rider or to Customer as a result of the application of Rate FT, the following charge shall apply to FT Pool Manager:

PS-FT Pool Administrative Charge: $75 per Customer in FT Pool per month

Other: In the event that FT Pool Manager is determined to be the cause of any billing disadvantages or other penalties imposed on Company by Pipeline Transporter, then FT Pool Manager shall pay such penalties, fees, or charges as determined by Company and in accordance with the payment provisions of this rate schedule in addition to any and all other charges due hereunder.

CHARACTER OF SERVICE

Service under this rider allows an FT Pool Manager to deliver to Company, on an aggregated basis, those natural gas supplies that are needed to satisfy the full requirements of one or more firm transportation customers that comprise a PS-FT Pool. Company may, in its sole discretion, issue an OFO to an individual Customer or an individual Pool Manager taking service under Rider PS-FT without issuing an OFO to all Customers taking service under Rate FT or without issuing an OFO to all Pool Managers taking service under Rider PS-FT. It is the responsibility of the FT Pool Manager to convey OFOs to Customers in its FT Pool.

The FT Pool Manager will be responsible for arranging for volumes of transportation gas to meet the daily and monthly requirements of Customers in the FT Pool. The FT Pool Manager shall be subject to the same nomination deadlines as set forth in Rate FT. The Daily Utilization Charge, OFO Penalty and cash-out provision of Rate FT shall be applied against the aggregate volume of all Customers in a specific FT Pool. The FT Pool Manager will be responsible for the payment of the PS-FT Pool Administrative Charge and any Daily Utilization Charges, OFO penalties or monthly cash-out payments incurred by a specific FT Pool as a result of imbalances under Rate FT.

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Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

CHARACTER OF SERVICE (continued)

daily imbalances that exceed ±5%. Company shall issue an Operational Flow Order as set forth in Rate FT to the FT Pool Manager during periods when service cannot be provided to meet daily imbalances.

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in an FT Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rate FT, and no customer shall participate in more than one FT Pool concurrently. Unless a Customer meets the provisions of the Remote Metering requirement under Rate FT, that Customer shall not participate in an FT Pool.

2. To receive service hereunder, the FT Pool Manager shall enter into a PS-FT Pool Management Agreement with Company and shall submit a PS-FT Application/Agency Agreement for each Customer in the FT Pool, signed by both Customer and its FT Pool Manager. The PS-FT Pool Management Agreement shall set forth the specific obligations of the FT Pool Manager and Company under this rider. The PS-FT Application/Agency Agreement shall set forth the Customers in the FT Pool.

   The FT Pool Manager shall submit a signed PS-FT Pool Management Agreement and a PS-FT Application/Agency Agreement for each Customer in the FT Pool at least thirty (30) days prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the FT Pool Manager of the date when service hereunder will commence. A Customer who terminates service under this rider or who desires to change FT Pool Managers shall likewise provide Company with a written notice at least thirty (30) days prior to the end of a billing period.

   The Pool Maximum Daily Quantity ("PMDQ") shall be set forth in the Pool Management Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the FT Pool. Company is not obligated to accept volumes for re-delivery on any day in excess of the PMDQ.

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Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

CHARACTER OF SERVICE (continued)

Company shall issue an Operational Flow Order as set forth in Rate FT to the FT Pool Manager during periods when service cannot be provided to meet daily imbalances. T

VARIATIONS IN MMBTU CONTENT

All gas delivered by Company will be measured and billed on an Mcf basis. Pipeline Transporter delivers to and bills Company on an MMBtu basis. The reconciliation of the actual deliveries by Pipeline Transporter and the Customer's estimated deliveries by Pipeline Transporter occurs through the operation of the monthly cash-out provision. Changes in billings of the cash-out provision caused by variations in the MMBtu content of the gas shall be corrected on the following bill.

SPECIAL TERMS AND CONDITIONS

1. No customer shall participate in an FT Pool that does not individually meet the conditions set forth in the "Availability of Service" under Rate FT, and no customer shall participate in more than one FT Pool concurrently. Unless a Customer meets the provisions of the Remote Metering requirement under Rate FT, that Customer shall not participate in an FT Pool.

2. To receive service hereunder, the FT Pool Manager shall enter into a PS-FT Pool Management Agreement with Company and shall submit a PS-FT Application/Agency Agreement for each Customer in the FT Pool, signed by both Customer and its FT Pool Manager. The PS-FT Pool Management Agreement shall set forth the specific obligations of the FT Pool Manager and Company under this rider. The PS-FT Application/Agency Agreement shall set forth the Customers in the FT Pool.

   The FT Pool Manager shall submit a signed PS-FT Pool Management Agreement and a PS-FT Application/Agency Agreement for each Customer in the FT Pool at least thirty (30) days prior to the beginning of a billing period when service under this rider shall commence. Company shall notify the FT Pool Manager of the date when service hereunder will commence. A Customer who terminates service under this rider or who desires to change FT Pool Managers shall likewise provide Company with a written notice at least thirty (30) days prior to the end of a billing period.

   The Pool Maximum Daily Quantity ("PMDQ") shall be set forth in the Pool Management Agreement. The PMDQ shall be equal to the total of the MDQs of all the Customers in the FT Pool. Company is not obligated to accept volumes for re-delivery on any day in excess of the PMDQ.

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State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 61.2
Canceling P.S.C. Gas No. 9, Original Sheet No. 61.2

Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

SPECIAL TERMS AND CONDITIONS (continued)

3. The FT Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure FT Pool Manager's performance of its obligations under the PS-FT Pool Management Agreement. In determining the level of the bond or other security to be required of an FT Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customers in the FT Pool, the general creditworthiness of the FT Pool Manager, and the FT Pool Manager's prior credit record with Company, if any. In the event that the FT Pool Manager defaults on its obligations under this rider or the PS-FT Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy FT Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-FT Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The FT Pool Manager shall provide Company with the written consent, in the form of a PS-FT Application/Agency Agreement, of all Customers to any change in the composition of the Customers in the FT Pool at least thirty (30) days prior to the beginning of the first billing period that would apply to the modified FT Pool Such written consent for existing Customers in the FT Pool to any change in the composition of the FT Pool may be made by the FT Pool Manager as Agent for the current Customers in the FT Pool. Without exception, any new Customer in the FT Pool must provide its own written consent in the form of a PS-FT Application/Agency Agreement.

5. The PS-FT Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if an FT Pool Manager fails to meet any condition of this rider and/or Rate FT. The PS-FT Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the FT Pool Manager has payments in arrears. Written notice of termination of the PS-FT Pool Management Agreement shall be provided both to the FT Pool Manager and to the individual Customers in the FT Pool by Company.

6. Company shall directly bill the FT Pool Manager for the PS-FT Pool Administrative Charge, Utilization Charge for Daily Imbalances, cash-out charges or payments, and OFO Charges contained in Rate FT. The bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty seven (27) days from the date of the bill, then the FT Pool Manager will be considered in default.

7. Company shall directly bill the individual customers in the FT Pool for all Distribution Charges, Administrative Charges, Gas Cost True-Up Charges, Minimum Daily Threshold Charges, and remote metering charges or payments provided for in Rate FT.

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Louisville Gas and Electric Company

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Standard Rate Rider **PS-FT**
Pooling Service – Rate FT

SPECIAL TERMS AND CONDITIONS (continued)

3. The FT Pool Manager shall upon request of Company agree to maintain a surety bond, an irrevocable letter of credit, or such other financial instrument satisfactory to Company in order to assure FT Pool Manager's performance of its obligations under the PS-FT Pool Management Agreement. In determining the level of the bond or other security to be required of an FT Pool Manager, Company shall consider such factors, including, but not limited to, the following: the volume of natural gas to be transported on behalf of Customers in the FT Pool, the general creditworthiness of the FT Pool Manager, and the FT Pool Manager's prior credit record with Company, if any. In the event that the FT Pool Manager defaults on its obligations under this rider or the PS-FT Pool Management Agreement, Company shall have the right to use the proceeds from such bond, irrevocable letter of credit, or other financial instrument to satisfy FT Pool Manager's obligation hereunder. Specific terms and conditions regarding credit requirements shall be included in the PS-FT Pool Management Agreement. Such credit requirements shall be administered by Company in a non-discriminatory manner.

4. The FT Pool Manager shall provide Company with the written consent, in the form of a PS-FT Application/Agency Agreement, of all Customers to any change in the composition of the Customers in the FT Pool at least thirty (30) days prior to the beginning of the first billing period that would apply to the modified FT Pool Such written consent for existing Customers in the FT Pool to any change in the composition of the FT Pool may be made by the FT Pool Manager as Agent for the current Customers in the FT Pool. Without exception, any new Customer in the FT Pool must provide its own written consent in the form of a PS-FT Application/Agency Agreement.

5. The PS-FT Pool Management Agreement may be terminated by Company upon thirty (30) days written notice if an FT Pool Manager fails to meet any condition of this rider and/or Rate FT. The PS-FT Pool Management Agreement may also be terminated by Company upon thirty (30) days written notice if the FT Pool Manager has payments in arrears. Written notice of termination of the PS-FT Pool Management Agreement shall be provided both to the FT Pool Manager and to the individual Customers in the FT Pool by Company.

6. Company shall directly bill the FT Pool Manager for the PS-FT Pool Administrative Charge, Utilization Charge for Daily Imbalances, cash-out charges or payments, and OFO Charges contained in Rate FT. The bill will be rendered at these net charges plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within fifteen (15) days from the date of the bill. If payment is not made within twenty seven (27) days from the date of the bill, then the FT Pool Manager will be considered in default.

7. Company shall directly bill the individual customers in the FT Pool for all Distribution Charges, Administrative Charges, Gas Cost True-Up Charges, Minimum Daily Threshold Charges, and remote metering charges or payments provided for in Rate FT.

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 62

Standard Rate Rider **EF**

Excess Facilities

APPLICABILITY

In all territory served.

AVAILABILITY OF SERVICE

This rider is available for nonstandard service facilities which are considered to be in excess of the standard facilities that would normally be provided by Company. This rider does not apply to main extensions or to other facilities which are necessary to provide basic gas service. Company reserves the right to decline to provide service hereunder for any project (a) that exceeds $100,000 or (b) where Company does not have sufficient expertise to install, operate, or maintain the facilities or (c) where the facilities do not meet Company's safety requirements, or (d) where the facilities are likely to become obsolete prior to the end of the initial contract term. Customers currently being served under the Excess Facilities Rider pursuant to Original Sheet No. 52 of LG&E's Tariff PSC. of Ky. Gas No. 6, shall continue to be served thereunder.

DEFINITION OF EXCESS FACILITIES

Excess facilities are equipment and devices which are installed in addition to or in substitution for the normal facilities required to render basic gas service and where such facilities are dedicated to a specific customer. Applications of excess facilities include, but are not limited to, redundant gas regulator capacity; gas filters/separators; odorant removal systems; gas compression equipment; indirect heaters; gas purification systems; additional facilities required for the customer to take service from a high-pressure gas line; and any other equipment/systems not normally installed to provide gas service to a customer.

EXCESS FACILITIES CHARGE

Company shall provide normal operation and maintenance of the excess facilities. Should the facilities suffer failure, Company will provide for replacement of such facilities and the monthly charge will be adjusted to reflect the installed cost of the replacement facilities. 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 0.47%

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 62

Standard Rate Rider **EF**

Excess Facilities

APPLICABILITY

In all territory served.

AVAILABILITY OF SERVICE

This rider is available for nonstandard service facilities which are considered to be in excess of the standard facilities that would normally be provided by Company. This rider does not apply to main extensions or to other facilities which are necessary to provide basic gas service. Company reserves the right to decline to provide service hereunder for any project (a) that exceeds $100,000 or (b) where Company does not have sufficient expertise to install, operate, or maintain the facilities or (c) where the facilities do not meet Company's safety requirements, or (d) where the facilities are likely to become obsolete prior to the end of the initial contract term. Customers currently being served under the Excess Facilities Rider pursuant to Original Sheet No. 52 of LG&E's Tariff PSC. of Ky. Gas No. 6, shall continue to be served thereunder.

DEFINITION OF EXCESS FACILITIES

Excess facilities are equipment and devices which are installed in addition to or in substitution for the normal facilities required to render basic gas service and where such facilities are dedicated to a specific customer. Applications of excess facilities include, but are not limited to, redundant gas regulator capacity; gas filters/separators; odorant removal systems; gas compression equipment; indirect heaters; gas purification systems; additional facilities required for the customer to take service from a high-pressure gas line; and any other equipment/systems not normally installed to provide gas service to a customer.

EXCESS FACILITIES CHARGE

Company shall provide normal operation and maintenance of the excess facilities. Should the facilities suffer failure, Company will provide for replacement of such facilities and the monthly charge will be adjusted to reflect the installed cost of the replacement facilities. 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 0.47%

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 62.1

Standard Rate Rider **EF**

Excess Facilities

PAYMENT

The Excess Facilities Charges shall be incorporated with the bill for gas service and will be subject to the same payment provisions.

TERM OF CONTRACT

The initial term of contract to Customer under this schedule shall be not less than five (5) years. The term shall continue automatically until terminated by either party upon at least one (1) month's written notice.

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P.S.C. Gas No. 10, Original Sheet No. 62.1

Standard Rate Rider **EF**

Excess Facilities

PAYMENT

The Excess Facilities Charges shall be incorporated with the bill for gas service and will be subject to the same payment provisions.

TERM OF CONTRACT

The initial term of contract to Customer under this schedule shall be not less than five (5) years. The term shall continue automatically until terminated by either party upon at least one (1) month's written notice.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

The proposed LG&E Natural Gas Vehicle Service Rider NGV is not part of the current tariff.

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 63

Standard Rate Rider **NGV** N

Natural Gas Vehicle Service

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

Applicable to municipal, utility, corporate and other fleet operators and public fueling stations meeting the qualifications of, and served under, either Rate IGS or Rate FT for the sole purpose of providing compressed natural gas for use as a fuel in vehicular internal combustion engines. Availability of gas service under this rate schedule shall be determined by Company on a case-by-case basis, which determination shall be within Company's sole discretion. Company shall not be obligated to make modifications or additions to its gas system to serve loads under this Rider.

Service provided under this Rider shall be separately metered. Service for any use of natural gas other than the compression of natural gas for vehicle fuel, such as space heating, water heating, or any direct processing or boiler fuel use, is not permitted under this Rider or through the meter through which service under this Rider is provided.

CHARACTER OF SERVICE

Company will provide Customer with uncompressed natural gas pursuant to either Rate IGS or Rate FT, as applicable. A customer served under Rate IGS that meets the qualifications for service under Rider TS-2 may also transport gas pursuant to Rider TS-2.

Customer shall be responsible for installing, owning, and maintaining all facilities required to operate its fueling station.

The compression of natural gas to the pressure required for use as a motor vehicle fuel will be conducted by Customer using facilities installed, owned and operated by Customer.

RATE

The rates, provisions, and special terms and conditions of Rate IGS, Rider TS-2, or Rate FT as applicable to the Customer shall apply.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

The proposed LG&E Natural Gas Vehicle Service Rider NGV is not part of the current tariff.

Standard Rate Rider **NGV**

Natural Gas Vehicle Service

N

SPECIAL CONDITIONS

1. Company reserves the right to inspect customer's premises to ensure gas provided pursuant to this Rider is only used for vehicular fuel. Any other use of gas by Customer may result in termination of service.

2. Service under this Rider shall be performed under a written contract between Customer and Company containing such provisions regarding delivery pressure, indemnification, and other matters as the Company deems necessary or desirable with respect to a particular customer.

3. Customer shall be responsible for and shall reimburse the Company for all taxes (including, but not limited to, any motor vehicle taxes) payable by the Company to any governmental body on sales of gas and/or for services rendered under this Rider.

4. The "Resale of Gas" provision set forth in the "Terms and Conditions" of Company's Tariff shall not apply to service provided under this Rider. Customer may resell gas received from Company under this Rider for use as a fuel in vehicular internal combustion engines.

5. Customer is solely responsible for compliance with codes and standards, permitting requirements, regulations, and laws related to the use of compressed natural gas and the operation of a natural gas vehicle fueling station, whether as a fleet operation or as a public fueling station. Company is not responsible for vehicle fueling.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto, to the extent that such Terms and Conditions are not in conflict with nor inconsistent with the specific provisions hereof.

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Second Revision of Original Sheet No. 84
Canceling P.S.C. Gas No. 9, First Revision of Original Sheet No. 84

Adjustment Clause **GLT**
Gas Line Tracker

APPLICABLE

Applicable to all customers receiving service under the Company's Rate Schedules RGS, VFD, CGS, IGS, AAGS, and DGGS.

CALCULATION OF THE GAS LINE TRACKER REVENUE REQUIREMENT

The GLT Revenue Requirement includes the following:

a. GLT related Plant In-Service not included in base gas rates minus the associated GLT related accumulated depreciation and accumulated deferred income taxes;
b. Retirement and removal of plant related to GLT construction;
c. The rate of return on the net rate base is the overall rate of return on capital authorized in the Company's latest base gas rate case, grossed up for federal and state income taxes;
d. Depreciation expense on the GLT-related Plant In-Service less retirement and removals; and
e. Incremental Operation and Maintenance

GLT PROGRAM FACTORS

All customers receiving service under rate schedules RGS, VFD, CGS, IGS, AAGS, and DGGS shall be assessed an adjustment to their applicable rate schedule that will enable the Company to recover the costs associated with the GLT program. After the Company replaces a gas service riser or a gas service line under this program, it will assume ownership and responsibility for the plant and equipment. The allocation of the program cost to customers will be in proportion to their relative base revenue share approved in Case No. 2012-00222.

A filing to update the projected program costs will be submitted annually at least two (2) months prior to the beginning of the effective period. The filing will reflect the anticipated impact on the Company's revenue requirements of net plant additions expected during the upcoming year. After the completion of a plan year, the Company will submit a balancing adjustment to true up the actual costs with the projected program costs for the preceding year. Such adjustment to the GLT will become effective with the first billing cycle on or after the effective date of such change.

GLT RATES

The charges for the respective gas service schedules are:

RGS – Residential Gas Service	$ 1.08
VFD – Volunteer Fire Department Service	$ 1.08
CGS – Commercial Gas Service	$ 4.83
IGS – Industrial Gas Service	$ 42.69
AAGS – As-Available Gas Service	$ 235.45
DGGS – Distributed Generation Gas Service	$ 0.00

DATE OF ISSUE: May 6, 2014

DATE EFFECTIVE: With Service Rendered On and After
April 29, 2014

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2014-00070 dated April 29, 2014

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 84

Adjustment Clause **GLT**
Gas Line Tracker

APPLICABLE

Applicable to all customers receiving service under the Company's Rate Schedules RGS, VFD, CGS, IGS, AAGS, and DGGS.

CALCULATION OF THE GAS LINE TRACKER REVENUE REQUIREMENT

The GLT Revenue Requirement includes the following:

a. GLT related Plant In-Service not included in base gas rates minus the associated GLT related accumulated depreciation and accumulated deferred income taxes;
b. Retirement and removal of plant related to GLT construction;
c. The rate of return on the net rate base is the overall rate of return on capital authorized in the Company's latest base gas rate case, grossed up for federal and state income taxes;
d. Depreciation expense on the GLT-related Plant In-Service less retirement and removals; and
e. Incremental Operation and Maintenance
f. Property Taxes T

GLT PROGRAM FACTORS

All customers receiving service under rate schedules RGS, VFD, CGS, IGS, AAGS, and DGGS shall be assessed an adjustment to their applicable rate schedule that will enable the Company to recover the costs associated with the GLT program. After the Company replaces a gas service riser or a gas service line under this program, it will assume ownership and responsibility for the plant and equipment. The allocation of the program cost to customers will be in proportion to their relative base revenue share approved in Case No. 2012-00222.

A filing to update the projected program costs will be submitted annually at least two (2) months prior to the beginning of the effective period. The filing will reflect the anticipated impact on the Company's revenue requirements of net plant additions expected during the upcoming year. After the completion of a plan year, the Company will submit a balancing adjustment to true up the actual costs with the projected program costs for the preceding year. Such adjustment to the GLT will become effective with the first billing cycle on or after the effective date of such change.

GLT RATES

The charges for the respective gas service schedules are:

RGS – Residential Gas Service	$ 1.08
VFD – Volunteer Fire Department Service	$ 1.08
CGS – Commercial Gas Service	$ 4.83
IGS – Industrial Gas Service	$ 42.69
AAGS – As-Available Gas Service	$ 235.45
DGGS – Distributed Generation Gas Service	$ 0.00

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Eighth Revision of Original Sheet No. 85
Canceling P.S.C. Gas No. 9, Seventh Revision of Original Sheet No. 85

Adjustment Clause **GSC**
Gas Supply Clause

APPLICABLE TO
All gas sold.

GAS SUPPLY COST COMPONENT (GSCC)

Gas Supply Cost	$0.50459
Gas Cost Actual Adjustment (GCAA)	0.05750
Gas Cost Balance Adjustment (GCBA)	(0.00584)
Refund Factors (RF) continuing for twelve months from the effective date of each or until Company has discharged its refund obligation thereunder:	
None	
Performance-Based Rate Recovery Component (PBRRC)	0.00503
Total Gas Supply Cost Component Per 100 Cubic Feet (GSCC)	$0.56128

DATE OF ISSUE: October 28, 2014

DATE EFFECTIVE: November 1, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00348 dated October 27, 2014

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 85

Adjustment Clause **GSC**
Gas Supply Clause

APPLICABLE TO
All gas sold.

GAS SUPPLY COST COMPONENT (GSCC)

Gas Supply Cost	$0.50459
Gas Cost Actual Adjustment (GCAA)	0.05750
Gas Cost Balance Adjustment (GCBA)	(0.00584)
Refund Factors (RF) continuing for twelve months from the effective date of each or until Company has discharged its refund obligation thereunder:	
None	
Performance-Based Rate Recovery Component (PBRRC)	0.00503
Total Gas Supply Cost Component Per 100 Cubic Feet (GSCC)	$0.56128

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: November 1, 2014

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2014-00348 dated October 27, 2014

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 85.1
Canceling P.S.C. Gas No. 9, Original Sheet No. 85.1

Adjustment Clause **GSC**
Gas Supply Clause

The bill amount computed under each of the rate schedules to which this Gas Supply Clause is applicable shall include a Gas Supply Cost Component per 100 cubic feet of consumption calculated for each three-month period in accordance with the following formula:

GSCC = Gas Supply Cost + GCAA + GCBA + RF + PBRRC

where:

Gas Supply Cost is the expected average cost per 100 cubic feet for each three-month period (beginning February 1, May 1, August 1, or November 1, as the case may be) determined by dividing the sum of the monthly gas supply costs by the expected deliveries to customers. Monthly gas supply cost is composed of the following:

(a) Expected purchased gas costs (gas supply and pipeline transportation) for system supply, minus

(b) Portion of such expected purchased gas costs expected to be used for non-Gas Department purposes, minus

(c) Portion of such expected purchased gas cost expected to be injected into underground storage, plus

(d) Expected underground storage withdrawals at the average unit cost of working gas contained therein;

(GCAA) is the Gas Cost Actual Adjustment per 100 cubic feet which compensates for differences between the previous three-month period's expected gas cost and the actual cost of gas during that three-month period, plus net uncollectible gas cost portion of bad debt.

(GCBA) is the Gas Cost Balance Adjustment per 100 cubic feet which compensates for any under- or over-collections which have occurred as a result of prior adjustments.

(RF) is the sum of the Refund Factors set forth on Sheet No. 85 of this Tariff.

(PBRRC) is the amount per 100 cubic feet calculated pursuant to the Experimental Performance-Based Rate Mechanism contained in the Adjustment Clause PBR. The PBRRC is determined for each 12-month PBR period ended October 31.

Company shall file a revised Gas Supply Cost Component (GSCC) every three months giving effect to known changes in the wholesale cost of all gas purchases and the cost of gas deliveries from underground storage. The Company may make out-of-time filings when warranted. Such filing shall be made at least thirty (30) days prior to the beginning of each three-month period and shall include the following information:

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 85.1

Adjustment Clause **GSC**
Gas Supply Clause

The bill amount computed under each of the rate schedules to which this Gas Supply Clause is applicable shall include a Gas Supply Cost Component per 100 cubic feet of consumption calculated for each three-month period in accordance with the following formula:

GSCC = Gas Supply Cost + GCAA + GCBA + RF + PBRRC

where:

Gas Supply Cost is the expected average cost per 100 cubic feet for each three-month period (beginning February 1, May 1, August 1, or November 1, as the case may be) determined by dividing the sum of the monthly gas supply costs by the expected deliveries to customers. Monthly gas supply cost is composed of the following:

(a) Expected purchased gas costs (gas supply and pipeline transportation) for system supply, minus

(b) Portion of such expected purchased gas costs expected to be used for non-Gas Department purposes, minus

(c) Portion of such expected purchased gas cost expected to be injected into underground storage, plus

(d) Expected underground storage withdrawals at the average unit cost of working gas contained therein;

(GCAA) is the Gas Cost Actual Adjustment per 100 cubic feet which compensates for differences between the previous three-month period's expected gas cost and the actual cost of gas during that three-month period, plus net uncollectible gas cost portion of bad debt.

(GCBA) is the Gas Cost Balance Adjustment per 100 cubic feet which compensates for any under- or over-collections which have occurred as a result of prior adjustments.

(RF) is the sum of the Refund Factors set forth on Sheet No. 85 of this Tariff.

(PBRRC) is the amount per 100 cubic feet calculated pursuant to the Experimental Performance-Based Rate Mechanism contained in the Adjustment Clause PBR. The PBRRC is determined for each 12-month PBR period ended October 31.

Company shall file a revised Gas Supply Cost Component (GSCC) every three months giving effect to known changes in the wholesale cost of all gas purchases and the cost of gas deliveries from underground storage. The Company may make out-of-time filings when warranted. Such filing shall be made at least thirty (30) days prior to the beginning of each three-month period and shall include the following information:

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 85.2
Canceling P.S.C. Gas No. 9, Original Sheet No. 85.2

Adjustment Clause **GSC**
Gas Supply Clause

1. A copy of the tariff rate(s) of Company's pipeline transporter(s) applicable to such three-month period.
2. A statement, through the most recent three-month period for which figures are available, setting out the accumulated costs recovered hereunder compared to actual gas supply costs recorded on the books.
3. A statement setting forth the supporting calculations of the Gas Supply Cost and the Gas Cost Actual Adjustment (GCAA) and the Gas Cost Balance Adjustment (GCBA) applicable to such three-month period.

To allow for the effect of Company's cycle billing, each change in the GSCC shall be placed into effect with service rendered on and after the first day of each three-month period.

In the event that Company receives from its supplier a cash refund of amounts paid to such supplier with respect to a prior period, Company will make adjustments in the amounts charged to its customers under this provision, as follows:

1. The "Refundable Amount" shall be the amount received by Company as a refund less any portion thereof applicable to gas purchased for electric energy production plus interest at a rate equal to the average of the "3-month commercial paper rate" for the immediately preceding 12-month period, less ½ of 1 percent to cover the cost of refunding in accordance with the Order of the Commission in Case No. 7799-D. Such Refundable Amount shall be divided by the number of hundred cubic feet of gas that Company estimates it will sell to its customers during the twelve-month period which commences with implementation of the next Gas Supply Clause filing, thus determining a "Refund Factor."
2. Effective with the implementation of the next Gas Supply Clause filing, Company will reduce, by the Refund Factor so determined, the Gas Supply Cost Component that would otherwise be applicable during the subsequent twelve-month period. Provided, however, that the period of reduced Gas Supply Cost Component will be adjusted, if necessary, in order to refund, as nearly as possible, the Refundable Amount.
3. In the event of any large or unusual refunds, Company may apply to the Public Service Commission of Kentucky for the right to depart from the refund procedure herein set forth.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 85.2

Adjustment Clause **GSC**
Gas Supply Clause

1. A copy of the tariff rate(s) of Company's pipeline transporter(s) applicable to such three-month period.
2. A statement, through the most recent three-month period for which figures are available, setting out the accumulated costs recovered hereunder compared to actual gas supply costs recorded on the books.
3. A statement setting forth the supporting calculations of the Gas Supply Cost and the Gas Cost Actual Adjustment (GCAA) and the Gas Cost Balance Adjustment (GCBA) applicable to such three-month period.

To allow for the effect of Company's cycle billing, each change in the GSCC shall be placed into effect with service rendered on and after the first day of each three-month period.

In the event that Company receives from its supplier a cash refund of amounts paid to such supplier with respect to a prior period, Company will make adjustments in the amounts charged to its customers under this provision, as follows:

1. The "Refundable Amount" shall be the amount received by Company as a refund less any portion thereof applicable to gas purchased for electric energy production plus interest at a rate equal to the average of the "3-month commercial paper rate" for the immediately preceding 12-month period, less ½ of 1 percent to cover the cost of refunding in accordance with the Order of the Commission in Case No. 7799-D. Such Refundable Amount shall be divided by the number of hundred cubic feet of gas that Company estimates it will sell to its customers during the twelve-month period which commences with implementation of the next Gas Supply Clause filing, thus determining a "Refund Factor."
2. Effective with the implementation of the next Gas Supply Clause filing, Company will reduce, by the Refund Factor so determined, the Gas Supply Cost Component that would otherwise be applicable during the subsequent twelve-month period. Provided, however, that the period of reduced Gas Supply Cost Component will be adjusted, if necessary, in order to refund, as nearly as possible, the Refundable Amount.
3. In the event of any large or unusual refunds, Company may apply to the Public Service Commission of Kentucky for the right to depart from the refund procedure herein set forth.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 86
Canceling P.S.C. Gas No. 9, Original Sheet No. 86

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to Residential Gas Service Rate RGS, Volunteer Fire Department Rate VFD, Firm Commercial Gas Service Rate CGS, Firm Industrial Gas Service Rate IGS, As-Available Gas Service Rate AAGS, Firm Gas Transportation Rate FT, and Gas Transportation Service/Standby Rider TS, and Gas Transportation Service/Firm Balancing Rider TS-2. Any industrial gas customer who also receives electric service from the Company as an industrial customer, and has elected not to participate in a demand-side management program hereunder, shall not be assessed a charge pursuant to this mechanism.

RATE

The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per 100 cubic feet (Ccf) of monthly gas consumption in accordance with the following formula:

DSMRC = DCR + DRLS + DSMI + DBA + DCCR

Where:

DCR = DSM COST RECOVERY

The DCR shall include all expected costs that have been approved by the Commission for each twelve-month period for demand-side management programs that have been developed through a collaborative advisory process (“approved programs”). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs. Program costs will be assigned for recovery purposes to the rate classes whose customers are directly participating in the program. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees and administrative expenses, will be recovered through the DCR. Administrative costs that are allocable to more than one rate class will be recovered from those classes and allocated by rate class on the basis of the estimated budget from each program.

The cost of approved programs shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DCR for such rate class.

DRLS = DSM REVENUE FROM LOST SALES

Revenues from lost sales due to DSM programs implemented on and after the effective date of this tariff will be recovered as follows:

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 86

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is mandatory to Residential Gas Service Rate RGS, Volunteer Fire Department
Service Rate VFD, Firm Commercial Gas Service Rate CGS, Firm Industrial Gas Service Rate T
IGS, As-Available Gas Service Rate AAGS, and Firm Transportation Rate FT. T

RATE

The monthly amount computed under each of the rate schedules to which this Demand-Side Management Cost Recovery Mechanism is applicable shall be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per 100 cubic feet (Ccf) of monthly gas consumption in accordance with the following formula:

DSMRC = DCR + DRLS + DSMI + DBA + DCCR

Where:

DCR = DSM COST RECOVERY

The DCR shall include all expected costs that have been approved by the Commission for each twelve-month period for demand-side management programs that have been developed through a collaborative advisory process (“approved programs”). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs. Program costs will be assigned for recovery purposes to the rate classes whose customers are directly participating in the program. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees and administrative expenses, will be recovered through the DCR. Administrative costs that are allocable to more than one rate class will be recovered from those classes and allocated by rate class on the basis of the estimated budget from each program.

The cost of approved programs shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DCR for such rate class.

DRLS = DSM REVENUE FROM LOST SALES

Revenues from lost sales due to DSM programs implemented on and after the effective date of this tariff will be recovered as follows:

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

DRLS = DSM REVENUE FROM LOST SALES (continued)

1. For each upcoming twelve-month period, the estimated reduction in customer usage (in Ccf) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per Ccf for purposes of determining the lost revenue to be recovered hereunder for each customer class. The non-variable revenue requirement is defined as the weighted average price per Ccf of expected Distribution Cost Component billings for the customer classes.

2. The lost revenues for each customer class shall then be divided by the estimated class sales (in Ccf) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenues from lost sales calculated for a twelve-month period shall be included in the DRLS for thirty-six (36) months or until implementation of new rates pursuant to a general rate case. For recovery purposes, the lost sales revenues will be assigned to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

DSMI = DSM INCENTIVE.
For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved programs that are to be installed during the upcoming twelve-month period times fifteen (15) percent, not to exceed five (5) percent of program expenditures. Net resource savings are defined as program benefits less utility program costs and participant costs where program benefits will be calculated on the basis of the present value of Company's avoided costs over the expected life of the program, and will include both capacity and energy savings. For the Energy Education Program, the DSM incentive amount shall be computed by multiplying the annual cost of the approved program times five (5) percent.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: With Bills Rendered On and
After December 31, 2011

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2011-00134 dated November 9, 2011

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

DRLS = DSM REVENUE FROM LOST SALES (continued)

1. For each upcoming twelve-month period, the estimated reduction in customer usage (in Ccf) as determined for the approved programs shall be multiplied by the non-variable revenue requirement per Ccf for purposes of determining the lost revenue to be recovered hereunder for each customer class. The non-variable revenue requirement is defined as the weighted average price per Ccf of expected Distribution Cost Component billings for the customer classes.

2. The lost revenues for each customer class shall then be divided by the estimated class sales (in Ccf) for the upcoming twelve-month period to determine the applicable DRLS surcharge. Recovery of revenues from lost sales calculated for a twelve-month period shall be included in the DRLS for thirty-six (36) months or until implementation of new rates pursuant to a general rate case. For recovery purposes, the lost sales revenues will be assigned to the rate classes whose programs resulted in the lost sales.

Revenues collected hereunder are based on engineering estimates of energy savings, expected program participation and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues actually collected hereunder and the lost revenues determined after any revisions of the engineering estimates and actual program participation are accounted for shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

A program evaluation vendor will be selected to provide evaluation criteria against which energy savings will be estimated for that program. Each program will be evaluated after implementation and any revision of the original engineering estimates will be reflected in both (a) the retroactive true-up provided for under the DSM Balance Adjustment and (b) the prospective future lost revenues collected hereunder.

DSMI = DSM INCENTIVE.
For all Energy Impact Programs except Direct Load Control, the DSM incentive amount shall be computed by multiplying the net resource savings expected from the approved programs that are to be installed during the upcoming twelve-month period times fifteen (15) percent, not to exceed five (5) percent of program expenditures. Net resource savings are defined as program benefits less utility program costs and participant costs where program benefits will be calculated on the basis of the present value of Company's avoided costs over the expected life of the program, and will include both capacity and energy savings. For the Energy Education Program, the DSM incentive amount shall be computed by multiplying the annual cost of the approved program times five (5) percent.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: With Bills Rendered On and
After December 31, 2011

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2011-00134 dated November 9, 2011

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 86.2

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

DSMI = DSM INCENTIVE (continued)

The DSM incentive amount shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DSMI. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

DBA = DSM BALANCE ADJUSTMENT.
The DBA shall be calculated on a calendar year basis and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, DCCR, and previous application of the DBA and the revenues that should have been billed, as follows:

(1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.

(2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.

(3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.

(4) For the DBA, the balance adjustment amount will be determined by calculating the difference between the amount billed during the twelve-month period from application of the DBA unit charges and the balance adjustment amount established for the same twelve-month period.

The balance adjustment amounts determined on the basis of the above paragraphs (1)-(4) shall include interest to be calculated at a rate equal to the average of the “Three-Month Commercial Paper Rate” for the immediately preceding twelve-month period. The balance adjustment amounts, plus interest, shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DBA for each rate class. DSM balance adjustment amounts will be assigned for recovery purposes to the rate classes for which over- or under-recoveries of DSM amounts were realized.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: With Bills Rendered On and
After December 31, 2011

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2011-00134 dated November 9, 2011**

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 86.2

Adjustment Clause **DSM**

Demand-Side Management Cost Recovery Mechanism

DSMI = DSM INCENTIVE (continued)

The DSM incentive amount shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DSMI. DSM incentive amounts will be assigned for recovery purposes to the rate classes whose programs created the incentive.

DBA = DSM BALANCE ADJUSTMENT.
The DBA shall be calculated on a calendar year basis and is used to reconcile the difference between the amount of revenues actually billed through the DCR, DRLS, DSMI, DCCR, and previous application of the DBA and the revenues that should have been billed, as follows:

(1) For the DCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the approved programs during the same twelve-month period.

(2) For the DRLS the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DRLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.

(3) For the DSMI, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DSMI unit charge and the incentive amount determined for the actual DSM measures implemented during the twelve-month period.

(4) For the DBA, the balance adjustment amount will be determined by calculating the difference between the amount billed during the twelve-month period from application of the DBA unit charges and the balance adjustment amount established for the same twelve-month period.

The balance adjustment amounts determined on the basis of the above paragraphs (1)-(4) shall include interest to be calculated at a rate equal to the average of the “Three-Month Commercial Paper Rate” for the immediately preceding twelve-month period. The balance adjustment amounts, plus interest, shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DBA for each rate class. DSM balance adjustment amounts will be assigned for recovery purposes to the rate classes for which over- or under-recoveries of DSM amounts were realized.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: With Bills Rendered On and
After December 31, 2011

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2011-00134 dated November 9, 2011**

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 86.3
Canceling P.S.C. Gas No. 9, Original Sheet No. 86.3

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

DCCR = DSM CAPITAL COST RECOVERY
The DCCR component is the means by which the Company recovers its capital investments made for DSM programs, as well as an approved rate of return on such capital investments. The Company calculates the DCCR component as follows:

$$DCCR = [(RB)\ (ROR + (ROR - DR)\ (TR / (1 - TR))] + OE$$

a) RB is the total rate base for DCCR projects.
b) ROR is the overall rate of return on DSM Rate Base (RB).
c) DR is the composite debt rate (i.e., the cost of short- and long-term debt) embedded in ROR.
d) TR is the composite federal and state income tax rate that applies to the equity return component of ROR.
e) OE is the sum of the capital-related operating expenses (i.e., depreciation and amortization expense, property taxes, and insurance expense) of the DSM projects to which DCCR applies.

The Company then allocates the DCCR component to the rate class(es) benefitting from the Company's various DSM-related capital investment(s).

CHANGES TO DSMRC

The filing of modifications to the DSMRC that require changes in the DCR component shall be made at least two (2) months prior to the beginning of the effective period for billing. Modifications to other components of the DSMRC shall be made at least thirty (30) days prior to the effective period for billing. Each filing shall include the following information as applicable:

(1) A detailed description of each DSM program developed by the collaborative process, the total cost of each program over the twelve-month period, an analysis of expected resource savings, information concerning the specific DSM or efficiency measures to be installed, and any applicable studies that have been performed, as available.

(2) A statement setting forth the detailed calculation of the DCR, DRLS, DSMI, DBA and DSMRC.

Each change in the DSMRC shall be placed into effect with bills rendered on and after the effective date of such change.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: May 31, 2012

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 86.3

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

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).

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The filing of modifications to the DSMRC that require changes in the DCR component shall be made at least two (2) months prior to the beginning of the effective period for billing. Modifications to other components of the DSMRC shall be made at least thirty (30) days prior to the effective period for billing. Each filing shall include the following information as applicable:

(1) A detailed description of each DSM program developed by the collaborative process, the total cost of each program over the twelve-month period, an analysis of expected resource savings, information concerning the specific DSM or efficiency measures to be installed, and any applicable studies that have been performed, as available.

(2) A statement setting forth the detailed calculation of the DCR, DRLS, DSMI, DBA and DSMRC.

Each change in the DSMRC shall be placed into effect with bills rendered on and after the effective date of such change.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: May 31, 2012

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 86.4
Canceling P.S.C. Gas No. 9, 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 RGS and VFD Standard Gas Rate Schedules.

Residential Conservation / Home Energy Performance Program
The on-site audit offers a comprehensive audit from a certified auditor and incentives for residential customers to support the implementation of energy saving measures for a fee of $25. Customers are eligible for incentives of $500 or $1,000 based on customer purchased and installed energy efficiency measures and validated through a follow-up test.

Residential Low Income Weatherization Program (WeCare)
The Residential Low Income Weatherization Program (WeCare) is an education and weatherization program designed to reduce energy consumption of LG&E’s low-income customers. The program provides energy audits, energy education, blower door tests, and installs weatherization and energy conservation measures. Qualified customers could receive energy conservation measures ranging from $0 to $2,100 based upon the customer’s most recent twelve month energy usage and results of an energy audit.

Smart Energy Profile
The Smart Energy Profile Program provides a portion of LG&E’s highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar properties in locality. The report will help the customer understand and make better informed choices as it relates to energy usage and the associated costs. Information presented in the report will include a comparison of the customer’s energy usage to that of similar houses (collectively) and a comparison to the customer’s own energy usage in the prior year.

Residential New Construction Program
The Residential New Construction program is designed to reduce residential energy usage and facilitate market transformation by creating a shift in builders’ new home construction to include energy-efficient construction practices. Builders who are part of the program can take advantage of technical training classes, gain additional exposure to potential customers and receive incentives to help offset costs when including more energy-efficient features during home construction. LG&E will reimburse the cost of plan reviews and inspection costs related to an Energy Star or HERS home certification.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: May 31, 2012

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 10, 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 RGS and VFD Standard Gas Rate Schedules.

Residential Conservation / Home Energy Performance Program
The on-site audit offers a comprehensive audit from a certified auditor and incentives for residential customers to support the implementation of energy saving measures for a fee of $25. Customers are eligible for incentives of $500 or $1,000 based on customer purchased and installed energy efficiency measures and validated through a follow-up test.

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The Smart Energy Profile Program provides a portion of LG&E’s highest consuming residential customers with a customized report of tips, tools and energy efficiency programming recommendations based on individual household energy consumption. These reports are benchmarked against similar properties in locality. The report will help the customer understand and make better informed choices as it relates to energy usage and the associated costs. Information presented in the report will include a comparison of the customer’s energy usage to that of similar houses (collectively) and a comparison to the customer’s own energy usage in the prior year.

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: May 31, 2012

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

PROGRAMMATIC CUSTOMER CHARGES (continued)

Customer Education and Public Information
These programs help customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through two processes: a mass-media campaign and an elementary- and middle-school program. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts.

Dealer Referral Network
The Dealer Referral Network assists customers in identifying qualified service providers to install energy efficiency improvements recommended and/ or subsidized by the various energy efficiency programs.

Commercial Customer Program Participation Incentives:
The following Demand Side Management programs are available to commercial customers receiving service from the Company on the CGS, IGS, AAGS, FT, TS, and TS-2 Standard Gas Rate Schedules and Riders.

Customer Education and Public Information
These programs help customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through two processes: a mass-media campaign and an elementary- and middle-school program. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts.

Dealer Referral Network
The Dealer Referral Network assists customers in identifying qualified service providers to install energy efficiency improvements recommended and/ or subsidized by the various energy efficiency programs.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

PROGRAMMATIC CUSTOMER CHARGES (continued)

Customer Education and Public Information
These programs help customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through two processes: a mass-media campaign and an elementary- and middle-school program. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts.

Dealer Referral Network
The Dealer Referral Network assists customers in identifying qualified service providers to install energy efficiency improvements recommended and/ or subsidized by the various energy efficiency programs.

Commercial Customer Program Participation Incentives:
The following Demand Side Management programs are available to commercial customers
receiving service from the Company on the CGS, IGS, AAGS, and FT Standard Gas Rate T
Schedules. T

Customer Education and Public Information
These programs help customers make sound energy-use decisions, increase control over energy bills and empower them to actively manage their energy usage. Customer Education and Public Information is accomplished through two processes: a mass-media campaign and an elementary- and middle-school program. The mass media campaign includes public-service advertisements that encourage customers to implement steps to reduce their energy usage. The elementary and middle school program provides professional development and innovative materials to K-8 schools to teach concepts such as basic energy and energy efficiency concepts.

Dealer Referral Network
The Dealer Referral Network assists customers in identifying qualified service providers to install energy efficiency improvements recommended and/ or subsidized by the various energy efficiency programs.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Third Revision of Original Sheet No. 86.6
Canceling P.S.C. Gas No. 9, Second Revision of Original Sheet No. 86.6

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors:

Residential Rate RGS and Volunteer Fire Department Rate VFD	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.01645 per Ccf
DSM Revenues from Lost Sales (DRLS)	$ 0.00316 per Ccf
DSM Incentive (DSMI)	$ 0.00075 per Ccf
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per Ccf
DSM Balance Adjustment (DBA)	$ (0.00413) per Ccf
Total DSMRC for Rates RGS and VFD	$ 0.01623 per Ccf

Commercial Customers Served Under Firm Commercial Gas Service Rate CGS, As-Available Gas Service Rate AAGS, Firm Transportation Rate FT, Gas Transportation Service/Standby Rider TS, and Gas Transportation Service/Firm Balancing Service Rider TS-2	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00089 per Ccf
DSM Revenues from Lost Sales (DRLS)	$ 0.00000 per Ccf
DSM Incentive (DSMI)	$ 0.00000 per Ccf
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per Ccf
DSM Balance Adjustment (DBA)	$ 0.00004 per Ccf
Total DSMRC for Rates CGS, AAGS, FT, TS, and TS-2	$ 0.00093 per Ccf

DATE OF ISSUE: February 28, 2014

DATE EFFECTIVE: April 1, 2014

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 86.6

Adjustment Clause **DSM**
Demand-Side Management Cost Recovery Mechanism

Monthly Adjustment Factors:

Residential Gas Service Rate RGS and Volunteer Fire Department Service Rate VFD	Energy Charge	T T
DSM Cost Recovery Component (DCR)	$ 0.01645 per Ccf	
DSM Revenues from Lost Sales (DRLS)	$ 0.00316 per Ccf	
DSM Incentive (DSMI)	$ 0.00075 per Ccf	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per Ccf	
DSM Balance Adjustment (DBA)	$ (0.00413) per Ccf	
Total DSMRC for Rates RGS and VFD	$ 0.01623 per Ccf	

Firm Commercial Gas Service Rate CGS, As-Available Gas Service Rate AAGS,* and Firm Transportation Service Rate FT*	Energy Charge	T T T
DSM Cost Recovery Component (DCR)	$ 0.00089 per Ccf	
DSM Revenues from Lost Sales (DRLS)	$ 0.00000 per Ccf	
DSM Incentive (DSMI)	$ 0.00000 per Ccf	
DSM Capital Cost Recovery Component (DCCR)	$ 0.00000 per Ccf	
DSM Balance Adjustment (DBA)	$ 0.00004 per Ccf	
Total DSMRC for Rates CGS, AAGS, and FT	$ 0.00093 per Ccf	T

* This charge does not apply to industrial customers taking service under these rates T
because the Company currently does not offer industrial DSM programs. T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 87
Canceling P.S.C. Gas No. 9, Original Sheet No. 87

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

APPLICABLE

To all gas sold.

RATE MECHANISM

The monthly amount computed under each of the rate schedules to which this Performance Based Ratemaking Mechanism is applicable shall be increased or decreased by the Performance Based Rate Recovery Component **(PBRRC)** at a rate per 100 cubic feet (Ccf) of monthly gas consumption. Demand costs and commodity costs shall be accumulated separately and included in the Pipeline Supplier's Demand Component and the Gas Supply Cost Component of the Gas Supply Clause (GSC), respectively. The PBRRC shall be determined for each 12-month period ended October 31 during the effective term of this experimental performance based ratemaking mechanism, which 12-month period shall be defined as the PBR period.

The PBRRC shall be computed in accordance with the following formula:

$$\mathbf{PBRRC} = \frac{\mathbf{CSPBR + BA}}{\mathbf{ES}}$$

Where:

ES = Expected Ccf sales, as reflected in Company's GSC filing for the upcoming 12-month period beginning February 1.

CSPBR = Company Share of Performance Based Ratemaking Mechanism savings or expenses. The CSPBR shall be calculated as follows:

$$\mathbf{CSPBR = TPBRR \times ACSP}$$

Where:

TPBRR = Total Performance Based Ratemaking Results. The TPBRR shall be savings or expenses created during the PBR Period. TPBRR shall be calculated as follows:

$$\mathbf{TPBRR = (GAIF + TIF + OSSIF)}$$

GAIF

GAIF = Gas Acquisition Index Factor. The GAIF shall be calculated by comparing the total annual Benchmark Gas Costs **(BGC)** for system supply natural gas purchases for the PBR period to the total annual Actual Gas Costs **(AGC)** for system supply natural gas purchases during the same period to determine if any Shared Expenses or Shared Savings exist.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: October 26, 2001

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 87

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

APPLICABLE

To all gas sold.

RATE MECHANISM

The monthly amount computed under each of the rate schedules to which this Performance Based Ratemaking Mechanism is applicable shall be increased or decreased by the Performance Based Rate Recovery Component **(PBRRC)** at a rate per 100 cubic feet (Ccf) of monthly gas consumption. Demand costs and commodity costs shall be accumulated separately and included in the Pipeline Supplier's Demand Component and the Gas Supply Cost Component of the Gas Supply Clause (GSC), respectively. The PBRRC shall be determined for each 12-month period ended October 31 during the effective term of this experimental performance based ratemaking mechanism, which 12-month period shall be defined as the PBR period.

The PBRRC shall be computed in accordance with the following formula:

$$\mathbf{PBRRC} = \frac{\mathbf{CSPBR + BA}}{\mathbf{ES}}$$

Where:

ES = Expected Ccf sales, as reflected in Company's GSC filing for the upcoming 12-month period beginning February 1.

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$$\mathbf{CSPBR = TPBRR \times ACSP}$$

Where:

TPBRR = Total Performance Based Ratemaking Results. The TPBRR shall be savings or expenses created during the PBR Period. TPBRR shall be calculated as follows:

$$\mathbf{TPBRR = (GAIF + TIF + OSSIF)}$$

GAIF

GAIF = Gas Acquisition Index Factor. The GAIF shall be calculated by comparing the total annual Benchmark Gas Costs **(BGC)** for system supply natural gas purchases for the PBR period to the total annual Actual Gas Costs **(AGC)** for system supply natural gas purchases during the same period to determine if any Shared Expenses or Shared Savings exist.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: October 26, 2001

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 87.1
Canceling P.S.C. Gas No. 9, Original Sheet No. 87.1

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

The BGC shall include two benchmark components as follows:

BGC = TABMGCC + HRF

Where:

TABMGCC represents the Total Annual Benchmark Gas Commodity Costs and is the annual sum of the monthly Benchmark Gas Commodity Costs **(BMGCC)** of gas purchased for system supply; and

HRF represents Historical Reservation Fees and is an annual dollar amount equal to Company's average annual supply reservation fees based on the 24-month period ended October 31 immediately preceding the PBR period.

BMGCC represents Benchmark Gas Commodity Costs and shall be calculated on a monthly basis and accumulated for the PBR period. BMGCC shall be calculated as follows:

BMGCC = Sum {[SZFQE%i x (APV - PEFDCQ)x SAIi]} + [PEFDCQ x DAI]

Where:

SZFQE% is the Supply Zone Firm Quantity Entitlement Percentage derived from Company's firm entitlements by pipeline and by zone for which indices are posted. The percentage represents the pro-rata portion of Company's firm lateral and mainline receipt point quantity entitlements by zone for each transportation contract by pipeline.

i represents each supply area.

APV is the actual purchased volumes of natural gas for system supply for the month. The APV shall include purchases necessary to cover retention volumes required by the pipeline as fuel.

PEFDCQ are the Purchases In Excess of Firm Daily Contract Quantities delivered to Company's city gate. Firm Daily Contract Quantities are the maximum daily contract quantities which Company can deliver to its city gate under its various firm transportation agreements and arrangements.

SAI is the Supply Area Index factor to be established for each supply area in which Company has firm transportation entitlements used to transport its natural gas purchases and for which price postings are available. The five supply areas are TGT-SL (Texas Gas Transmission - Zone SL), TGT-1 (Texas Gas Transmission - Zone 1), TGT-4 (Texas Gas Transmission – Zone 4), TGPL-0 (Tennessee Gas Pipeline - Zone 0), and TGPL-1 (Tennessee Gas Pipeline - Zone 1).

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: November 1, 2001

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00550 dated April 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 87.1

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

The BGC shall include two benchmark components as follows:

BGC = TABMGCC + HRF

Where:

TABMGCC represents the Total Annual Benchmark Gas Commodity Costs and is the annual sum of the monthly Benchmark Gas Commodity Costs **(BMGCC)** of gas purchased for system supply; and

HRF represents Historical Reservation Fees and is an annual dollar amount equal to Company's average annual supply reservation fees based on the 24-month period ended October 31 immediately preceding the PBR period.

BMGCC represents Benchmark Gas Commodity Costs and shall be calculated on a monthly basis and accumulated for the PBR period. BMGCC shall be calculated as follows:

BMGCC = Sum {[SZFQE%i x (APV - PEFDCQ)x SAIi]} + [PEFDCQ x DAI]

Where:

SZFQE% is the Supply Zone Firm Quantity Entitlement Percentage derived from Company's firm entitlements by pipeline and by zone for which indices are posted. The percentage represents the pro-rata portion of Company's firm lateral and mainline receipt point quantity entitlements by zone for each transportation contract by pipeline.

i represents each supply area.

APV is the actual purchased volumes of natural gas for system supply for the month. The APV shall include purchases necessary to cover retention volumes required by the pipeline as fuel.

PEFDCQ are the Purchases In Excess of Firm Daily Contract Quantities delivered to Company's city gate. Firm Daily Contract Quantities are the maximum daily contract quantities which Company can deliver to its city gate under its various firm transportation agreements and arrangements.

SAI is the Supply Area Index factor to be established for each supply area in which Company has firm transportation entitlements used to transport its natural gas purchases and for which price postings are available. The five supply areas are TGT-SL (Texas Gas Transmission - Zone SL), TGT-1 (Texas Gas Transmission - Zone 1), TGT-4 (Texas Gas Transmission – Zone 4), TGPL-0 (Tennessee Gas Pipeline - Zone 0), and TGPL-1 (Tennessee Gas Pipeline - Zone 1).

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: November 1, 2001

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00550 dated April 30, 2010

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

The monthly SAI for TGT-SL, TGT-1, TGT-4, TGPL-0 and TGPL-1 shall be calculated using the following formula:

SAI = [I(1) + I(2) + I(3)] / 3

DAI is the Delivery Area Index to be established for purchases made by Company when Company has fully utilized its pipeline quantity entitlements on a daily basis and which are for delivery to Company's city gate from either Texas Gas Transmission's Zone 4 or Tennessee Gas Pipeline's Zone 2.

The monthly DAI for TGT-4 and TGPL-2 shall be calculated using the following formula:

DAI = [I(1) + I(2) + I(3)] / 3

Where:

I represents each index reflective of both supply area prices and price changes throughout the month in these various supply areas.

The indices for each supply zone are as follows:

SAI (TGT-SL)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for Louisiana - Onshore South Texas Gas Zone SL averaged for the month.

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas Zone SL.

SAI (TGT-1)

I(1) is the average of weekly *Natural Gas Week* postings for North Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for East Texas - North Louisiana Area -Texas Gas Zone 1 averaged for the month.

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas Zone1.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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2012-00222 dated December 20, 2012

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

The monthly SAI for TGT-SL, TGT-1, TGT-4, TGPL-0 and TGPL-1 shall be calculated using the following formula:

SAI = [I(1) + I(2) + I(3)] / 3

DAI is the Delivery Area Index to be established for purchases made by Company when Company has fully utilized its pipeline quantity entitlements on a daily basis and which are for delivery to Company's city gate from either Texas Gas Transmission's Zone 4 or Tennessee Gas Pipeline's Zone 2.

The monthly DAI for TGT-4 and TGPL-2 shall be calculated using the following formula:

DAI = [I(1) + I(2) + I(3)] / 3

Where:

I represents each index reflective of both supply area prices and price changes throughout the month in these various supply areas.

The indices for each supply zone are as follows:

SAI (TGT-SL)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for Louisiana - Onshore South Texas Gas Zone SL averaged for the month.

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas Zone SL.

SAI (TGT-1)

I(1) is the average of weekly *Natural Gas Week* postings for North Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for East Texas - North Louisiana Area -Texas Gas Zone 1 averaged for the month.

I(3) is the *Platts Inside FERC's Gas Market Report* first-of-the-month posting for Texas Gas Zone1.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 87.3
Canceling P.S.C. Gas No. 9, Original Sheet No. 87.3

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

SAI (TGT-4)

I(1) is the average of weekly *Natural Gas Week* postings for Spot Prices on Interstate Pipeline Systems for Lebanon Hub.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for Appalachia – Lebanon Hub averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Northeast – Lebanon Hub.

SAI (TGPL-0)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Texas as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for South – Corpus Christi-Tennessee averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee Zone 0.

SAI (TGPL-1)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for Louisiana – Onshore South – Tennessee 500 Leg averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee 500 leg.

DAI (TGT-4) and (TGPL-2)

I(1) is the average of weekly *Natural Gas Week* postings for Spot Prices on Interstate Pipeline Systems for Dominion - South.

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 87.3

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

SAI (TGT-4)

I(1) is the average of weekly *Natural Gas Week* postings for Spot Prices on Interstate Pipeline Systems for Lebanon Hub.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for Appalachia – Lebanon Hub averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Northeast – Lebanon Hub.

SAI (TGPL-0)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Texas as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for South – Corpus Christi-Tennessee averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee Zone 0.

SAI (TGPL-1)

I(1) is the average of weekly *Natural Gas Week* postings for Gulf Coast Onshore Louisiana as Delivered to Pipeline.

I(2) is the average of the daily high and low *Platts Gas Daily* postings for Louisiana – Onshore South – Tennessee 500 Leg averaged for the month.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Tennessee 500 leg.

DAI (TGT-4) and (TGPL-2)

I(1) is the average of weekly *Natural Gas Week* postings for Spot Prices on Interstate Pipeline Systems for Dominion - South.

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 87.4
Canceling P.S.C. Gas No. 9, Original Sheet No. 87.4

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

I(2) is the average of the daily high and low *Platts Gas Daily* postings for the Daily Price Survey for Appalachia - Dominion South Point.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Prices of Spot Gas Delivered to Pipeline for Dominion Transmission Inc. - Appalachia.

AGC represents Company's total annual Actual Gas Costs of natural gas purchased for system supply and is equal to the total monthly actual gas commodity costs and supply reservation fees plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments paid by Company to its suppliers accumulated for the PBR period. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

To the extent that AGC exceeds BGC for the PBR period, then the GAIF Shared Expenses shall be computed as follows:

Shared Expenses = AGC - BGC

To the extent that AGC is less than BGC for the PBR period, then the GAIF Shared Savings shall be computed as follows:

Shared Savings = BGC – AGC

TIF

TIF = Transportation Index Factor. The Transportation Index Factor shall be calculated by comparing the Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** of natural gas transportation services during the PBR period, to the Total Annual Actual Gas Transportation Costs **(TAAGTC)** applicable to the same period to determine if any Shared Expenses or Shared Savings exist.

The Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** are calculated as follows:

TABMGTC = Annual Sum of Monthly BMGTC

Where:

BMGTC is the Benchmark Monthly Gas Transportation Costs which include both demand and volumetric costs associated with natural gas pipeline transportation services. The BMGTC shall be accumulated for the PBR period and shall be calculated as follows:

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State Regulation and Rates
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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 87.4

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

I(2) is the average of the daily high and low *Platts Gas Daily* postings for the Daily Price Survey for Appalachia - Dominion South Point.

I(3) is the *Platts Inside FERC's - Gas Market Report* first-of-the-month posting for Prices of Spot Gas Delivered to Pipeline for Dominion Transmission Inc. - Appalachia.

AGC represents Company's total annual Actual Gas Costs of natural gas purchased for system supply and is equal to the total monthly actual gas commodity costs and supply reservation fees plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments paid by Company to its suppliers accumulated for the PBR period. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

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To the extent that AGC is less than BGC for the PBR period, then the GAIF Shared Savings shall be computed as follows:

Shared Savings = BGC – AGC

TIF

TIF = Transportation Index Factor. The Transportation Index Factor shall be calculated by comparing the Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** of natural gas transportation services during the PBR period, to the Total Annual Actual Gas Transportation Costs **(TAAGTC)** applicable to the same period to determine if any Shared Expenses or Shared Savings exist.

The Total Annual Benchmark Monthly Gas Transportation Costs **(TABMGTC)** are calculated as follows:

TABMGTC = Annual Sum of Monthly BMGTC

Where:

BMGTC is the Benchmark Monthly Gas Transportation Costs which include both demand and volumetric costs associated with natural gas pipeline transportation services. The BMGTC shall be accumulated for the PBR period and shall be calculated as follows:

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 87.5
Canceling P.S.C. Gas No. 9, Original Sheet No. 87.5

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

BMGTC = Sum [BM(TGT) + BM(TGPL) + BM(PPL)]

Where:

BM(TGT) is the benchmark associated with Texas Gas Transmission Corporation.

BM(TGPL) is the benchmark associated with Tennessee Gas Pipeline Company.

BM(PPL) is the benchmark associated with a proxy pipeline. The appropriate benchmark, which will be determined at the time of purchase, will be used to benchmark purchases of transportation capacity from non-traditional sources.

The benchmark associated with each pipeline shall be calculated as follows:

BM(TGT) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(TGPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(PPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

Where:

TPDR is the applicable Tariffed Pipeline Demand Rate.
DQ is the Demand Quantities contracted for by Company from the applicable transportation provider.

TPCR is the applicable Tariffed Pipeline Commodity Rate.

AV is the Actual Volumes delivered at Company's city-gate by the applicable transportation provider for the month.

S&DB represents Surcharges, Direct Bills and other applicable amounts approved by the Federal Energy Regulatory Commission (FERC). Such amounts are limited to FERC-approved charges such as surcharges, direct bills, cashouts, take-or-pay amounts, Gas Supply Realignment and other Order 636 transition costs.

The Total Annual Actual Gas Transportation Costs (**TAAGTC)** paid by Company for the PBR period shall include both demand and volumetric costs associated with natural gas pipeline transportation services as well as all applicable FERC-approved surcharges, direct bills and cash-outs included in S&DB, plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 87.5

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

BMGTC = Sum [BM(TGT) + BM(TGPL) + BM(PPL)]

Where:

BM(TGT) is the benchmark associated with Texas Gas Transmission Corporation.

BM(TGPL) is the benchmark associated with Tennessee Gas Pipeline Company.

BM(PPL) is the benchmark associated with a proxy pipeline. The appropriate benchmark, which will be determined at the time of purchase, will be used to benchmark purchases of transportation capacity from non-traditional sources.

The benchmark associated with each pipeline shall be calculated as follows:

BM(TGT) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(TGPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

BM(PPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

Where:

TPDR is the applicable Tariffed Pipeline Demand Rate.
DQ is the Demand Quantities contracted for by Company from the applicable transportation provider.

TPCR is the applicable Tariffed Pipeline Commodity Rate.

AV is the Actual Volumes delivered at Company's city-gate by the applicable transportation provider for the month.

S&DB represents Surcharges, Direct Bills and other applicable amounts approved by the Federal Energy Regulatory Commission (FERC). Such amounts are limited to FERC-approved charges such as surcharges, direct bills, cashouts, take-or-pay amounts, Gas Supply Realignment and other Order 636 transition costs.

The Total Annual Actual Gas Transportation Costs (**TAAGTC)** paid by Company for the PBR period shall include both demand and volumetric costs associated with natural gas pipeline transportation services as well as all applicable FERC-approved surcharges, direct bills and cash-outs included in S&DB, plus the gains and/or losses from the use of financial hedging instruments and the financial transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 87.6
Canceling P.S.C. Gas No. 9, Original Sheet No. 87.6

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

To the extent that TAAGTC exceeds TABMGTC for the PBR period, then the TIF Shared Expenses shall be computed as follows:

Shared Expenses = TAAGTC – TABMGTC

To the extent that TAAGTC is less than TABMGTC for the PBR period, then the TIF Shared Savings shall be computed as follows:

Shared Savings = TABMGTC - TAAGTC

Should one of Company's pipeline transporters file a rate change effective during any PBR period and bill such proposed rates subject to refund, the period over which the benchmark comparison is made for the relevant transportation costs will be extended for one or more 12-month periods, until the FERC has approved final settled rates, which will be used as the appropriate benchmark. Company will not share in any of the savings or expenses related to the affected pipeline until final settled rates are approved.

OSSIF

OSSIF = Off-System Sales Index Factor. The Off-System Sales Index Factor shall be equal to the Net Revenue from Off-System Sales **(NR)**.

Net Revenue is calculated as follows:

NR = OSREV - OOPC

Where:

OSREV is the total revenue associated with off-system sales and storage service transactions.

OOPC is the out-of-pocket costs associated with off-system sales and storage service transactions, and shall be determined as follows:

OOPC = OOPC(GC) + OOPC(TC) + OOPC(SC) + OOPC(UGSC) + Other Costs

Where:

OOPC(GC) is the Out-of-Pocket Gas Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm supply contracts, the OOPC(GC) shall be the incremental cost to purchase the gas available under Company's firm supply contracts. For off-system sales not using Company's firm supply contracts, the OOPC(GC) shall be the incremental costs to purchase the gas from other entities.

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 87.6

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

To the extent that TAAGTC exceeds TABMGTC for the PBR period, then the TIF Shared Expenses shall be computed as follows:

Shared Expenses = TAAGTC – TABMGTC

To the extent that TAAGTC is less than TABMGTC for the PBR period, then the TIF Shared Savings shall be computed as follows:

Shared Savings = TABMGTC - TAAGTC

Should one of Company's pipeline transporters file a rate change effective during any PBR period and bill such proposed rates subject to refund, the period over which the benchmark comparison is made for the relevant transportation costs will be extended for one or more 12-month periods, until the FERC has approved final settled rates, which will be used as the appropriate benchmark. Company will not share in any of the savings or expenses related to the affected pipeline until final settled rates are approved.

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Where:

OOPC(GC) is the Out-of-Pocket Gas Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm supply contracts, the OOPC(GC) shall be the incremental cost to purchase the gas available under Company's firm supply contracts. For off-system sales not using Company's firm supply contracts, the OOPC(GC) shall be the incremental costs to purchase the gas from other entities.

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 87.7
Canceling P.S.C. Gas No. 9, Original Sheet No. 87.7

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

OOPC(TC) is the Out-of-Pocket Transportation Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm transportation agreements, the OOPC(TC) shall be the incremental cost to use the transportation available under Company's firm supply contracts. For off-system sales not using Company's firm transportation agreements, the OOPC(TC) shall be the incremental costs to purchase the transportation from other entities.

OOPC(SC) is the Out-of-Pocket Storage Costs associated with off-system sales of storage. If this is gas in Company's own storage it shall be priced at the average price of the gas in Company's storage during the month of the sale. If this is gas from the storage component of Texas Gas's No-Notice Service, this gas shall be priced at the replacement cost.

OOPC(UGSC) is the Out-of-Pocket Underground Storage Costs associated with off-system sales of storage services. For the off-systems sales of storage services utilizing Company's on-system storage, the OOPC(UGSC) shall include incremental storage losses, odorization, and other fuel-related costs such as purification, dehydration, and compression. Such costs shall exclude labor-related expenses.

Other Costs represent all other incremental costs and include, but are not limited to, costs such as applicable sales taxes and excise fees plus the gains and/or losses from the use of financial hedging instruments and the transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

ACSP

ACSP = Applicable Company Sharing Percentage. The ACSP shall be determined based on the PTAGSC.

Where:

PTAGSC = Percentage of Total Actual Gas Supply Costs. The PTAGSC shall be the TPBRR stated as a Percentage of Total Actual Gas Supply Costs and shall be calculated as follows:

$$\mathbf{PTAGSC} = \frac{\mathbf{TPBRR}}{\mathbf{TAGSC}}$$

Where:

TAGSC = Total Actual Gas Supply Costs. The TAGSC shall be calculated as follows:

$$\mathbf{TAGSC} = \mathbf{AGC} + \mathbf{TAAGTC}$$

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P.S.C. Gas No. 10, Original Sheet No. 87.7

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

OOPC(TC) is the Out-of-Pocket Transportation Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm transportation agreements, the OOPC(TC) shall be the incremental cost to use the transportation available under Company's firm supply contracts. For off-system sales not using Company's firm transportation agreements, the OOPC(TC) shall be the incremental costs to purchase the transportation from other entities.

OOPC(SC) is the Out-of-Pocket Storage Costs associated with off-system sales of storage. If this is gas in Company's own storage it shall be priced at the average price of the gas in Company's storage during the month of the sale. If this is gas from the storage component of Texas Gas's No-Notice Service, this gas shall be priced at the replacement cost.

OOPC(UGSC) is the Out-of-Pocket Underground Storage Costs associated with off-system sales of storage services. For the off-systems sales of storage services utilizing Company's on-system storage, the OOPC(UGSC) shall include incremental storage losses, odorization, and other fuel-related costs such as purification, dehydration, and compression. Such costs shall exclude labor-related expenses.

Other Costs represent all other incremental costs and include, but are not limited to, costs such as applicable sales taxes and excise fees plus the gains and/or losses from the use of financial hedging instruments and the transaction costs associated with such instruments. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

ACSP

ACSP = Applicable Company Sharing Percentage. The ACSP shall be determined based on the PTAGSC.

Where:

PTAGSC = Percentage of Total Actual Gas Supply Costs. The PTAGSC shall be the TPBRR stated as a Percentage of Total Actual Gas Supply Costs and shall be calculated as follows:

$$\mathbf{PTAGSC} = \frac{\mathbf{TPBRR}}{\mathbf{TAGSC}}$$

Where:

TAGSC = Total Actual Gas Supply Costs. The TAGSC shall be calculated as follows:

$$\mathbf{TAGSC} = \mathbf{AGC} + \mathbf{TAAGTC}$$

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DATE EFFECTIVE: November 1, 2010

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State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 87.8
Canceling P.S.C. Gas No. 9, Original Sheet No. 87.8

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

If the absolute value of the PTAGSC is less than or equal to 4.5%, then the ACSP of 25% shall be applied to TPBRR to determine CSPBR. If the absolute value of the PTAGSC is greater than 4.5%, then the ACSP of 25% shall be applied to the amount of TPBRR that is equal to 4.5% of TAGSC to determine a portion of CSPBR, and the ACSP of 50% shall be applied to the amount of TPBRR that is in excess of 4.5% of TAGSC to determine a portion of CSPBR. These two portions are added together to produce the total CSPBR.

BA

BA = Balance Adjustment. The BA is used to reconcile the difference between the amount of revenues billed or credited through the CSPBR and previous application of the BA and revenues which should have been billed or credited, as follows:

1) For the CSPBR, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the CSPBR and the actual amount used to establish the CSPBR for the period.

2) For the BA, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the BA and the actual amount used to establish the BA for the period.

Review

Within 60 days of the end of the fourth year of the five-year extension, Company will file an assessment and review of the PBR mechanism for the first four years of the five-year extension period. In that report and assessment, Company will make any recommended modifications to the PBR mechanism.

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DATE EFFECTIVE: November 1, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
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Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 87.8

Adjustment Clause **PBR**
Experimental Performance Based Rate Mechanism

If the absolute value of the PTAGSC is less than or equal to 4.5%, then the ACSP of 25% shall be applied to TPBRR to determine CSPBR. If the absolute value of the PTAGSC is greater than 4.5%, then the ACSP of 25% shall be applied to the amount of TPBRR that is equal to 4.5% of TAGSC to determine a portion of CSPBR, and the ACSP of 50% shall be applied to the amount of TPBRR that is in excess of 4.5% of TAGSC to determine a portion of CSPBR. These two portions are added together to produce the total CSPBR.

BA

BA = Balance Adjustment. The BA is used to reconcile the difference between the amount of revenues billed or credited through the CSPBR and previous application of the BA and revenues which should have been billed or credited, as follows:

1) For the CSPBR, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the CSPBR and the actual amount used to establish the CSPBR for the period.

2) For the BA, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the BA and the actual amount used to establish the BA for the period.

Review

Within 60 days of the end of the fourth year of the five-year extension, Company will file an assessment and review of the PBR mechanism for the first four years of the five-year extension period. In that report and assessment, Company will make any recommended modifications to the PBR mechanism.

DATE OF ISSUE: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 88

Adjustment Clause **WNA**

Weather Normalization Adjustment Clause Applicable to Rates RGS and CGS

WEATHER NORMALIZATION ADJUSTMENT (WNA)

The sales to Residential and Commercial Customers under Rate Schedules RGS and CGS shall be increased or decreased monthly by an amount hereinafter described as the Weather Normalization Adjustment (WNA).

Determination of WNA

Weather normalized volumes shall be utilized during the November through April billing periods to calculate the non-gas portion of the bills of all heating Customers served under Rate Schedules RGS and CGS. During the remainder of the year, May through October, the bills shall be computed based on actual consumption.

Weather Normalization Adjustment will be calculated using the following formula:

WNA = [(Actual Mcf - Base Load Mcf) * (Normal Degree Days/Actual Degree Days)]

Each Customer's base load will be determined individually, and will be recomputed annually. Rates used in the computation of the WNA shall be determined based on the applicable base rate charge as set forth on the RGS and CGS Rate Schedules.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: September 7, 2000

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00459 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 88

Adjustment Clause **WNA**

Weather Normalization Adjustment Clause Applicable to Rates RGS and CGS

WEATHER NORMALIZATION ADJUSTMENT (WNA)

The sales to Residential and Commercial Customers under Rate Schedules RGS and CGS shall be increased or decreased monthly by an amount hereinafter described as the Weather Normalization Adjustment (WNA).

Determination of WNA

Weather normalized volumes shall be utilized during the November through April billing periods to calculate the non-gas portion of the bills of all heating Customers served under Rate Schedules RGS and CGS. During the remainder of the year, May through October, the bills shall be computed based on actual consumption.

Weather Normalization Adjustment will be calculated using the following formula:

WNA = [(Actual Mcf - Base Load Mcf) * (Normal Degree Days/Actual Degree Days)]

Each Customer's base load will be determined individually, and will be recomputed annually. Rates used in the computation of the WNA shall be determined based on the applicable base rate charge as set forth on the RGS and CGS Rate Schedules.

DATE OF ISSUE: November 26,2014

DATE EFFECTIVE: September 7, 2000

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00459 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 90

Adjustment Clause

Franchise Fee

APPLICABILITY

All gas rate schedules.

MONTHLY CHARGE

A surcharge shall be calculated and added to the total bill for gas service for all customers located within local governmental jurisdictions which currently or in the future impose municipal franchise fees or other local taxes on the Company by ordinance, franchise, or otherwise. Such fees or taxes shall be net of any corresponding fees or taxes which are currently included in the base charges of each rate schedule.

The amount calculated shall be applied exclusively to the bills of customers receiving service within the territorial limits of the authority imposing the fee or tax. The fee or tax shall be added to the customer's bill as a separate item. Where more than one such fee or tax is imposed, each of the fees or taxes applicable to each customer shall be added to the bills as separately identified items.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: February 6, 2009

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 90

Adjustment Clause

Franchise Fee

APPLICABILITY

All gas rate schedules.

MONTHLY CHARGE

A surcharge shall be calculated and added to the total bill for gas service for all customers located within local governmental jurisdictions which currently or in the future impose municipal franchise fees or other local taxes on the Company by ordinance, franchise, or otherwise. Such fees or taxes shall be net of any corresponding fees or taxes which are currently included in the base charges of each rate schedule.

The amount calculated shall be applied exclusively to the bills of customers receiving service within the territorial limits of the authority imposing the fee or tax. The fee or tax shall be added to the customer's bill as a separate item. Where more than one such fee or tax is imposed, each of the fees or taxes applicable to each customer shall be added to the bills as separately identified items.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: February 6, 2009

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Adjustment Clause **ST**

School Tax

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This schedule is applied as a rate increase to all other schedules pursuant to KRS 160.617 for the recovery by the utility of school taxes in any county requiring a utility gross receipts license tax for schools under KRS 160.613.

RATE

The utility gross receipts license tax authorized under state law.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: August 1, 2010

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2009-00549 dated July 30, 2010

Adjustment Clause **HEA**
Home Energy Assistance

APPLICABLE
In all territory served.

AVAILABILITY
To all residential customers.

RATE
$0.25 per meter per month.

BILLING
The HEA charge shall be shown as a separate item on customer bills.

SERVICE PERIOD
The Home Energy Assistance charge will be applied to all residential gas bills rendered during the billing cycles commencing January 1, 2013 until the effective date of new base rates, or as otherwise directed by the Public Service Commission. The HEA program is approved through September 30, 2015. 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: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Adjustment Clause **HEA**
Home Energy Assistance

APPLICABLE
In all territory served.

AVAILABILITY
To all residential customers.

RATE
$0.25 per meter per month.

BILLING
The HEA charge shall be shown as a separate item on customer bills.

SERVICE PERIOD
The Home Energy Assistance charge will be applied to all residential gas bills rendered during the billing cycles commencing January 1, 2013 until the effective date of new base rates, or as otherwise directed by the Public Service Commission. The HEA program is approved through September 30, 2015. 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.

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 95

TERMS AND CONDITIONS

Customer Bill of Rights

As a residential customer of a regulated public utility in Kentucky, you are guaranteed the following rights subject to Kentucky Revised Statutes and the provisions of the Kentucky Public Service Commission Administrative Regulations:

- You have the right to service, provided you (or a member of your household whose debt was accumulated at your address) are not indebted to the utility.
- You have the right to inspect and review the utility's rates and tariffed operating procedures during the utility's normal office hours.
- You have the right to be present at any routine utility inspection of your service conditions.
- You must be provided a separate, distinct disconnect notice alerting you to a possible disconnection of your service, if payment is not received.
- You have the right to dispute the reasons for any announced termination of your service.
- You have the right to negotiate a partial payment plan when your service is threatened by disconnection for non-payment.
- You have the right to participate in equal, budget payment plans for your natural gas and electric service.
- You have the right to maintain your utility service for up to thirty (30) days upon presentation of a medical certificate issued by a health official.
- You have the right to prompt (within 24 hours) restoration of your service when the cause for discontinuance has been corrected.
- If you have not been disconnected, you have the right to maintain your natural gas and electric service for up to thirty (30) days, provided you present a Certificate of Need issued by the Kentucky Cabinet for Human Resources between the months of November and the end of March.
- If you have been disconnected due to non-payment, you have the right to have your natural gas or electric service reconnected between the months of November through March provided you:
    1) Present a Certificate of Need issued by the Kentucky Cabinet for Human Resources, and
    2) Pay one third (1/3) of your outstanding bill ($200 maximum), and
    3) Accept referral to the Human Resources' Weatherization Program, and
    4) Agree to a repayment schedule that will cause your bill to become current by October 15.
- You have the right to contact the Public Service Commission regarding any dispute that you have been unable to resolve with your utility (call Toll Free 1-800-772-4636).

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 95

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Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 96

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

All gas service supplied by Company shall be in accordance with the applicable rules and regulations of the Public Service Commission of Kentucky.

COMPANY TERMS AND CONDITIONS.

In addition to the rules and regulations of the Commission, all gas service supplied by Company shall be in accordance with these Terms and Conditions which shall constitute a part of all applications and contracts for service.

RATES, TERMS AND CONDITIONS ON FILE

A copy of the rate schedules, terms, and conditions under which gas service is supplied is on file with the Public Service Commission of Kentucky. A copy of such rate schedules, terms and conditions, together with the law, rules, and regulations of the Commission, is available for public inspection in each office of Company where bills may be paid.

ASSIGNMENT

No order for service, agreement or contract for service may be assigned or transferred without the written consent of Company.

RENEWAL OF CONTRACT

If, upon the expiration of any service contract for a specified term, the customer continues to use the service, the contract (unless otherwise provided therein) will be automatically renewed for successive periods of one (1) year each, subject to termination at the end of any year upon thirty (30) days prior written notice by either party.

AGENTS CANNOT MODIFY AGREEMENT WITHOUT CONSENT OF P.S.C. OF KY.

No agent has power to amend, modify, alter, or waive any of these Terms and Conditions, or to bind Company by making any promises or representations not contained herein.

SUPERSEDE PREVIOUS TERMS AND CONDITIONS

These Terms and Conditions supersede all terms and conditions under which Company has previously supplied gas service

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 96

TERMS AND CONDITIONS

General

COMMISSION RULES AND REGULATIONS

All gas service supplied by Company shall be in accordance with the applicable rules and regulations of the Public Service Commission of Kentucky.

COMPANY TERMS AND CONDITIONS.

In addition to the rules and regulations of the Commission, all gas service supplied by Company shall be in accordance with these Terms and Conditions which shall constitute a part of all applications and contracts for service.

COMPANY AS A FEDERAL CONTRACTOR T

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 gas service is supplied is on file with the Public Service Commission of Kentucky. A copy of such rate schedules, terms and conditions, together with the law, rules, and regulations of the Commission, is available for public inspection in each office of Company where bills may be paid.

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T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

LG&E TERMS and CONDITIONS – General is now contained on two pages instead of the current one page.

TERMS AND CONDITIONS

General

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AGENTS CANNOT MODIFY AGREEMENT WITHOUT CONSENT OF P.S.C. OF KY.

No agent has power to amend, modify, alter, or waive any of these Terms and Conditions, or to bind Company by making any promises or representations not contained herein.

SUPERSEDE PREVIOUS TERMS AND CONDITIONS

These Terms and Conditions supersede all terms and conditions under which Company has previously supplied gas service

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Customer Responsibilities

APPLICATION FOR SERVICE

A written application or contract, properly executed, may be required before Company is obligated to render gas service. Company shall have the right to reject for valid reasons any such application or contract.

All applications for service shall be made in the legal name of the party desiring the service.

Where an unusual expenditure for construction or equipment is necessary or where the proposed manner of using gas service is clearly outside the scope of Company's standard rate schedules, Company may establish special terms and require special contracts giving effect to such unusual circumstances.

TRANSFER OF APPLICATION

Applications for gas service are not transferable and new occupants of premises will be required to make application for service before commencing the use of gas. Customers who have been receiving gas service shall notify Company when discontinuance of service is desired, and shall pay for all gas service furnished until such notice has been given and final meter readings made by Company.

OPTIONAL RATES

If two or more rate schedules are available for the same class of service, it is Customer's responsibility to determine the options available and to designate the schedule under which Customer desires to receive service.

Company will, at any time, upon request, advise any Customer as to the most advantageous rate for existing or anticipated service requirements as defined by the Customer, but Company does not assume responsibility for the selection of such rate or for the continuance of the lowest annual cost under the rate selected.

In those cases in which the most favorable rate is difficult to predetermine, the Customer will be given the opportunity to change to another schedule, unless otherwise prevented by the rate schedule under which Customer is currently served, after trial of the schedule originally designated; however, after the first such change, Company shall not be required to make a change in schedule more often than once in twelve months.

From time to time, Customer should investigate Customer's operating conditions to determine a desirable change from one available rate to another. Company, lacking knowledge of changes that may occur at any time in Customer's operating conditions, does not assume responsibility that Customers will at all times be served under the most beneficial rate.

In no event will Company make refunds covering the difference between the charges under the rate in effect and those under any other rate applicable to the same class of service.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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TERMS AND CONDITIONS

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2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

Customer Responsibilities

CUSTOMER’S EQUIPMENT AND INSTALLATION.

Customer shall furnish, install, and maintain at Customer’s expense the necessary Customer's Service Line extending from Company's Service Connection at the property line to the building or place of utilization of the gas.

All piping, appliances, and other gas equipment and apparatus, except the meter, regulator, and any gas riser or service line the Company has installed, repaired, or replaced, located on and within the Customer's premises beyond point of connection with Company's Service Connection at the property line shall be furnished and installed by and at the expense of Customer, and shall be maintained by Customer in good and safe condition. Company assumes no responsibility whatsoever for the condition of Customer's piping, apparatus or appliances, nor for the maintenance or renewal of any portion thereof.

OWNER'S CONSENT TO OCCUPY

Customer shall grant easements and rights-of-way on and across Customer's property at no cost to Company.

ACCESS TO PREMISES AND EQUIPMENT

Company shall have the right of access to Customer's premises at all reasonable times for the purpose of installing, meter reading, inspecting, repairing, or removing its equipment used in connection with its supply of gas service or for the purpose of turning on and shutting off the gas supply when necessary and for all other proper purposes. Customer shall not construct or permit the construction of any structure or device which will restrict the access of Company to its equipment for any of the above purposes.

PROTECTION OF COMPANY'S PROPERTY

Customers will be held responsible for tampering, interfering with, breaking of seals of meters, or other equipment of Company installed on Customer's premises, and will be held liable for same according to law. Customer hereby agrees that no one except the employees of Company shall be allowed to make any internal or external adjustments of any meter or any other piece of apparatus which shall be the property of Company.

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED

Gas service shall not be used for purposes other than as set forth in customer's application or contract.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

Customer Responsibilities

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DATE OF ISSUE: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

Customer Responsibilities

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED (continued)

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. Company and Customer may mutually agree to enter into a special contract for standby, back-up, supplemental or other service subject to the approval of the Kentucky Public Service Commission.

LIABILITY

Customer assumes all responsibility for the gas service upon Customer's premises at and from the point of delivery of gas and for the pipes and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of gas, occasioned by such gas or said pipes and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence of Company.

NOTICE TO COMPANY OF CHANGES IN CUSTOMER'S LOAD

The service pipes, meters, and appurtenances supplied by Company for the rendition of gas service to its customers have a definite capacity. In the event that Customer contemplates any material increase in Customer's connected load, whether in a single increment or over an extended period, Customer shall immediately give Company written notice of this fact so as to enable it to enlarge the capacity of such equipment. In case of failure to give such notice, Customer may be held liable for any damage done to meters, regulators, or other equipment of Company caused by such material increase in Customer's connected load.

PERMITS

Customer shall obtain or cause to be obtained all permits, easements, or certificates, except street permits, necessary to give Company or its agents access to Customer's premises and equipment and to enable its service to be connected therewith. In case Customer is not the owner of the premises or of intervening property between the premises and Company's distribution mains, Customer shall obtain from the proper owner or owners the necessary consent to the installation and maintenance in said premises and across such intervening property of Customer's piping and facilities required for the supply of gas service to Customer. Provided, however, to the extent permits, easements, or certificates are necessary for the installation and maintenance of Company-owned facilities, Company shall obtain the aforementioned consent.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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2012-00222 dated December 20, 2012**

TERMS AND CONDITIONS

Customer Responsibilities

EXCLUSIVE SERVICE ON INSTALLATION CONNECTED (continued)

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. Company and Customer may mutually agree to enter into a special contract for standby, back-up, supplemental or other service subject to the approval of the Kentucky Public Service Commission.

LIABILITY

Customer assumes all responsibility for the gas service upon Customer's premises at and from the point of delivery of gas and for the pipes and equipment used in connection therewith, and will protect and save Company harmless from all claims for injury or damage to persons or property occurring on Customer's premises or at and from the point of delivery of gas, occasioned by such gas or said pipes and equipment, except where said injury or damage will be shown to have been occasioned solely by the negligence of Company.

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DATE OF ISSUE: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Public Service Commission in Case No.
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TERMS AND CONDITIONS

Customer Responsibilities

PERMITS (continued)

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.

COMPANY-OWNED SERVICE LINES

The Company will install, own, operate and maintain the service line at the premises of residential and commercial customers, if such premises are not connected to a Company main by a service line. With respect to residential and commercial customers that occupy premises already connected to a Company main by a service line that the Company has installed, repaired, or replaced, the Company shall be responsible for operating and maintaining the customer service line and when the Company determines that replacement of such customer service line is necessary the Company shall be responsible for installing the service line and shall thereafter own the service line.

Any customer accepting gas service under this section shall be deemed to have granted the Company an easement across his property for such service. No service line shall be installed across private property other than the premises of the building to be supplied with gas, except after special investigation and approval by the Company.

When the length of the service pipe required between the property line and the meter is 100 feet or less, the Company will assess no charge for the service pipe installation.

When the length of required service pipe exceeds 100 feet, the Company may require the applicant to contribute toward the cost of the service line installation an amount equal to the estimated cost per foot for each lineal foot of service beyond 100 feet. Contributions by customers toward the Company's cost of furnishing and installing service lines in accordance with this section are non-refundable.

In the event that the Company is required to undertake any excavation on a customer's property in connection with the installation, repair, maintenance or replacement of a service line, the Company shall make reasonable efforts to restore the property to its original condition pursuant to generally accepted utility standards for such construction operations.

DATE OF ISSUE: January 31, 2013

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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TERMS AND CONDITIONS

Customer Responsibilities

PERMITS (continued)

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.

COMPANY-OWNED SERVICE LINES

The Company will install, own, operate and maintain the service line at the premises of residential and commercial customers, if such premises are not connected to a Company main by a service line. With respect to residential and commercial customers that occupy premises already connected to a Company main by a service line that the Company has installed, repaired, or replaced, the Company shall be responsible for operating and maintaining the customer service line and when the Company determines that replacement of such customer service line is necessary the Company shall be responsible for installing the service line and shall thereafter own the service line.

Any customer accepting gas service under this section shall be deemed to have granted the Company an easement across his property for such service. No service line shall be installed across private property other than the premises of the building to be supplied with gas, except after special investigation and approval by the Company.

When the length of the service pipe required between the property line and the meter is 100 feet or less, the Company will assess no charge for the service pipe installation.

When the length of required service pipe exceeds 100 feet, the Company may require the applicant to contribute toward the cost of the service line installation an amount equal to the estimated cost per foot for each lineal foot of service beyond 100 feet. Contributions by customers toward the Company's cost of furnishing and installing service lines in accordance with this section are non-refundable.

In the event that the Company is required to undertake any excavation on a customer's property in connection with the installation, repair, maintenance or replacement of a service line, the Company shall make reasonable efforts to restore the property to its original condition pursuant to generally accepted utility standards for such construction operations.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 98
Canceling P.S.C. Gas No. 9, Original Sheet No. 98

TERMS AND CONDITIONS

Company Responsibilities

METERING

The gas used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

POINT OF DELIVERY OF GAS

The point of delivery of gas supplied by Company shall be at the point where the gas passes from the pipes of Company's Service Connection into Customer's Service Line, irrespective of the location of the metering and regulating equipment.

If the Service Line is owned by the Customer, the point of delivery of gas supplied by the Company shall be at the point where the gas passes from the pipes of Company’s Service Connection into Customer’s Service Line, irrespective of the location of the metering and regulation equipment.

If the Service Line is owned by the Company, the point of delivery of gas supplied by the Company shall be at the point where the gas passes from the outlet of the meter to the Customer’s yard line or house piping.

COMPANY'S EQUIPMENT AND INSTALLATION

The Company shall furnish, install, and maintain at its expense the necessary service connection. The location of this service connection will be made at the discretion and judgment of the Company.

The Company will furnish, install, and maintain at its expense the necessary meter, regulator, and connections which will be located at or near the building, at the discretion or judgment of the Company. Suitable site or location for the meter, meter stand (including meter riser), and regulator and connections shall be provided by the Customer and title to this equipment shall remain in the Company with the right to install, operate, maintain, and remove same and no charge shall be made by the Customer for use of the premises as occupied or used. Customer shall protect such property of Company from loss or damage, and no one who is not an agent of Company shall be permitted to remove, damage or tamper with the same. Customer shall execute a reasonable form of easement agreement, if requested by Company.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 10, Original Sheet No. 98

TERMS AND CONDITIONS

Company Responsibilities

METERING

The gas used will be measured by a meter or meters to be furnished and installed by Company at its expense and all bills will be calculated upon the registration of said meters. When service is supplied by Company at more than one delivery point on the same premises, each delivery point will be metered and billed separately on the rate applicable. Meters include all measuring instruments. Meters will be located outside whenever possible. Otherwise, meters will be located as near as possible to the service entrance and on the ground floor of the building, in a clean, dry, safe and easily accessible place, free from vibration, agreed to by Company.

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DATE OF ISSUE: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 98.1
Canceling P.S.C. Gas No. 9, Original Sheet No. 98.1

TERMS AND CONDITIONS

Company Responsibilities

COMPANY'S EQUIPMENT AND INSTALLATION (continued)

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 gas requirements.

COMPANY NOT LIABLE FOR INTERRUPTIONS

Company will exercise reasonable care and diligence in an endeavor to supply gas service continuously and without interruption, except as provided in the terms of certain rate schedules; however, Company does not guarantee continuous service and shall not be liable for any loss or damage resulting from interruption, reduction, delay or failure of gas service not caused by the willful negligence of Company, or resulting from any cause or circumstance beyond the reasonable control of Company.

COMPANY NOT LIABLE FOR DAMAGE ON CUSTOMER'S PREMISES

Company is merely a supplier of gas service delivered at Company's property line, and shall not be liable for and shall be protected and held harmless for any injury or damage to persons or property of the Customer or of third persons resulting from the presence, use or abuse of gas on the Customer's premises or resulting from defects in or accidents to any of Customer's piping, equipment, apparatus or appliances, or resulting from any cause whatsoever other than the negligence of Company.

LIABILITY

In no event shall Company have any liability to the Customer or any other party affected by the gas service to the Customer for any consequential, indirect, incidental, special, or punitive damages, and such limitation of liability shall apply regardless of claim or theory. In addition, to the extent that Company acts within its rights as set forth herein and/or any applicable law or regulation, Company shall have no liability of any kind to the Customer or any other party. In the event that the Customer's use of Company's service causes damage to Company's property or injuries to persons, the Customer shall be responsible for such damage or injury and shall indemnify, defend, and hold Company harmless from any and all suits, claims, losses, and expenses associated therewith.

OBLIGATION TO SERVE

Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis to any

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 98.1

TERMS AND CONDITIONS

Company Responsibilities

COMPANY'S EQUIPMENT AND INSTALLATION (continued)

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 gas requirements.

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 98.2
Canceling P.S.C. Gas No. 9, Original Sheet No. 98.2

TERMS AND CONDITIONS

Company Responsibilities

Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. Company and Customer may mutually agree to enter into a special contract for standby, back-up, supplemental or other service subject to the approval of the Kentucky Public Service Commission.

SPECIAL RULES FOR CUSTOMERS SERVED FROM HIGH PRESSURE MAINS, GAS TRANSMISSION MAINS, AND STORAGE GATHERING LINES

In order to ensure the integrity, safe operations, and reliability of the Company's gas system, these special rules apply to customers served from high pressure mains, gas transmission mains, and storage gathering lines.

When a customer requests service from a high pressure main, gas transmission main, or storage gathering line under Rate RGS, CGS, IGS, VFD, AAGS, or FT, Company shall determine, in its sole discretion, if service is justified, feasible, and consistent with good operating practice.

Upon approval by Company of a request by a customer (or group of customers) for service from a high pressure main, gas transmission main, or storage gathering line, then Company may charge the customer (or group of customers) in addition to the charges under the applicable rate schedule, the estimated installed cost of the tap, any regulation equipment, piping, and any other equipment or facilities determined by Company, in its sole discretion, to be necessary to provide such service consistent with good operating practice.

In no case, shall Company be obligated to provide service to customers served under Rate DGGS from a high pressure main, gas transmission main, or storage gathering line.

PURCHASE OF CERTAIN CUSTOMER-OWNED GAS SERVICE ENTRANCES AND RISERS.

LG&E will reimburse its gas customers who have replaced their service entrances or gas risers (or both) between January 1, 2011 and December 31, 2012. Customers must notify LG&E if they desire such reimbursement. LG&E has no obligation to seek out such customers. LG&E will post on its website a notice of the availability of this reimbursement. The reimbursement will be in the amount of the customers' reasonable costs of replacing such service entrances or gas risers (or both), which must be demonstrated to LG&E's reasonable satisfaction. Customers disputing the amount of reimbursement may contact the Commission. LG&E will reimburse only owners of affected properties, each of whom must have owned the affected property at the time of the replacement of the service entrance or gas riser.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 98.2

TERMS AND CONDITIONS

Company Responsibilities

Customer that is physically connected to the facilities of any other provider of natural gas service, such other providers to include, but not be limited to, another natural gas local distribution company, public, private, or municipal; a producer, gatherer, or transmitter of natural gas; an interstate or intrastate natural gas pipeline; or any other entity (including the Customer itself acting in any one or more of these roles) that provides natural gas or natural gas service to residential, commercial, industrial, public authority, or any other type of customers which might otherwise receive natural gas from Company. Company and Customer may mutually agree to enter into a special contract for standby, back-up, supplemental or other service subject to the approval of the Kentucky Public Service Commission.

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 99

TERMS AND CONDITIONS

Character of Service

HEATING VALUE

Company will normally supply natural gas having a heating value of approximately 1,000 Btu per cubic foot or as is otherwise supplied by the interstate pipeline(s) from which Company takes natural gas service. All gas received into the system of Company shall meet either of the applicable quality standards of the interstate pipeline delivering natural gas to Company or the lowest standard if there is more than one pipeline. Company reserves the right to refuse to accept gas from any entity whose gas does not meet those minimum standards. When it is necessary to supplement the supply of natural gas, Company reserves the right, at its discretion, to supplement its supply of natural gas with a mixture of vaporized liquefied petroleum gas and air.

STANDARD PRESSURE AND MEASUREMENT BASE

The standard distribution pressure of the gas supplied by Company is four ounces per square inch above atmospheric pressure.

Atmospheric pressure shall be assumed in all cases to be 14.5 pounds per square inch and temperature shall be assumed to be 60 degrees Fahrenheit; provided, however, Company reserves the right for billing purposes to correct as necessary the actual temperature to a 60 degree Fahrenheit basis in the case of large volume customers.

All gas measured at pressures higher than the standard pressure shall be converted to a pressure base of 14.73 pounds per square inch absolute for billing purposes.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 99

TERMS AND CONDITIONS

Character of Service

HEATING VALUE

Company will normally supply natural gas having a heating value of approximately 1,000 Btu per cubic foot or as is otherwise supplied by the interstate pipeline(s) from which Company takes natural gas service. All gas received into the system of Company shall meet either of the applicable quality standards of the interstate pipeline delivering natural gas to Company or the lowest standard if there is more than one pipeline. Company reserves the right to refuse to accept gas from any entity whose gas does not meet those minimum standards. When it is necessary to supplement the supply of natural gas, Company reserves the right, at its discretion, to supplement its supply of natural gas with a mixture of vaporized liquefied petroleum gas and air.

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All gas measured at pressures higher than the standard pressure shall be converted to a pressure base of 14.73 pounds per square inch absolute for billing purposes.

DELIVERY PRESSURE T
Company shall not be obligated to provide gas service to any Customer at a minimum delivery T
pressure greater than 50 psig or the expected minimum pipeline pressure, whichever is less. T

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 101
Canceling P.S.C. Gas No. 9, Original Sheet No. 101

TERMS AND CONDITIONS

Billing

METER READINGS AND BILLS

Each bill for utility service shall be issued in compliance with 807 KAR 5:006, Section 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 electric or gas meter fails to register properly by reason of damage, accident, etc., Company shall have the right to estimate Customer's consumption during the period of failure on the basis of such factors as Customer's connected load, heating degree days, and consumption during a previous corresponding period and during a test period immediately following replacement of the defective meter.

Where Company serves a customer with both electric and gas service at the same service location, Company will render a combined bill. However, a residential customer may request, and Company will render, separate bills under the following conditions: (1) Customer is being threatened with disconnection for non-payment or has already been disconnected for that reason and (2) Customer would be able to pay either the gas or electric portion of his bill and thus retain one service.

Bills are due and payable at the office of Company during business hours, or at other locations designated by Company, within sixteen (16) business days (no less than twenty-two (22) calendar days) from the 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

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 101

TERMS AND CONDITIONS

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Second Revision of Original Sheet No. 101.1
Canceling P.S.C. Gas No. 9, First Revision of Original Sheet No. 101.1

TERMS AND CONDITIONS

Billing

METER READINGS AND BILLS (continued)

receipt of such pledge or notice. There will be no adverse credit impact on the customer's payment and credit record, including credit scoring, both internally and externally, and the account will not be considered delinquent for any purpose if the Company receives the customer's payment within fifteen days after the date on which the Company issues the customer's bill.

Failure to receive a bill does not exempt Customer from these provisions of Company's Terms and Conditions.

READING OF SEPARATE METERS NOT COMBINED

For billing purposes, each meter upon Customer's premises will be considered separately and readings of two or more meters will not be combined except where Company's operating convenience requires the installation of two or more meters upon Customer's premises instead of one meter.

CUSTOMER RATE MIGRATION

Unless otherwise specified in the applicable rate schedule or rider, a change from one rate to another will be effective with the first full billing period following a customer's request for such change or with a rate change mandated by changes in a customer's load. In cases where a change from one rate to another necessitates a change in metering, the change from one rate to another will be effective with the first full billing period following the meter change.

MONITORING OF CUSTOMER USAGE

In order to detect unusual deviations in individual Customer consumption, Company will monitor the usage of each Customer at least once 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 the Customer's consumption be found which cannot be attributed to a readily identified cause, Company may perform a detailed analysis of the Customer's meter reading and billing records. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, Company may contact Customer by telephone or in writing to determine whether there have been changes such as different number of household members or work staff, additional or different appliances, changes in business volume, or known leaks in the Customer's service line. Where the deviation is not otherwise explained, Company will test Customer's meter to determine whether the results show the meter is within the limits allowed by 807 KAR 5:022, Section 8(3)(a)1, and Section 8(3)(b)1. Company will notify the customers of the investigation, its findings, and any refunds or back-billing in accordance with 807 KAR 5:006, Section 11(4) and (5).

DATE OF ISSUE: April 22, 2013

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 101.1

TERMS AND CONDITIONS

Billing

METER READINGS AND BILLS (continued)

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 101.2

TERMS AND CONDITIONS

Billing

RESALE OF GAS

Gas service furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such gas to any other person, firm, or corporation on Customer's premises or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company's billing.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 101.2

TERMS AND CONDITIONS

Billing

RESALE OF GAS

Gas service furnished under Company's standard application or contract is for the use of Customer only and Customer shall not resell such gas to any other person, firm, or corporation on Customer's premises or for use on any other premises. This does not preclude Customer from allocating Company's billing to Customer to any other person, firm, or corporation provided the sum of such allocations does not exceed Company's billing.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 102
Canceling P.S.C. Gas No. 9, Original Sheet No. 102

TERMS AND CONDITIONS

Deposits

GENERAL

1) Company may require a cash deposit or other guaranty from customers to secure payment of bills in accordance with 807 KAR 5:006, Section 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 customers the option of paying all or a portion of their deposits in installments over a period not to exceed the first four (4) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.
5) The General Terms and Conditions regarding Deposits set forth above shall not apply to, and shall be superseded by, the deposit requirements set forth in Section 3 of the Special Terms and Conditions contained in Standard Rate Rider PS-TS-2 (Sheet No. 59.5), Standard Rate Rider PS-TS (Sheet No. 60.1), and Standard Rate Rider PS-FT (Sheet No. 61.1).

RESIDENTIAL

1) Residential customers are those customers served under Residential Gas Service, Sheet No. 5.
2) The deposit for a residential customer is in the amount of $95.00, which is calculated in accordance with 807 KAR5:006, Section 8(1)(d). For combination gas and electric customers, the total deposit will be $230.00.
3) Company shall retain Customer's deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No.10, 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 customers the option of paying all or a portion of their deposits in installments over a period not to exceed the first four (4) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4) Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills, except that no refund or credit will be made if Customer's bill is delinquent on the anniversary date of the deposit. If interest is paid or credited to Customer's bill prior to twelve (12) months from the date of deposit, the payment or credit will be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill, with any remainder refunded to Customer.
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RESIDENTIAL

1) Residential customers are those customers served under Residential Gas Service, Sheet No. 5.
2) The deposit for a residential customer is in the amount of $100.00, which is calculated in I
accordance with 807 KAR5:006, Section 8(1)(d). For combination gas and electric
customers, the total deposit will be $260.00. I
3) Company shall retain Customer's deposit for a period not to exceed twelve (12) months, provided Customer has met satisfactory payment and credit criteria.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 102.1
Canceling P.S.C. Gas No. 9, Original Sheet No. 102.1

TERMS AND CONDITIONS

Deposits

RESIDENTIAL (continued)

4) If a deposit is held longer than eighteen (18) months, the deposit will be recalculated, at Customer’s request, and based on Customer’s actual usage. If the deposit on account differs from the recalculated amount by more than $10.00, Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
5) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

OTHER SERVICE

1) The deposit for all other customers, those not classified herein as residential, shall not exceed 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly in accordance with 807 KAR5:006, Section 8(1)(d).
2) For customers not meeting the parameters of GENERAL ¶ 2, Company may retain Customer’s deposit as long as Customer remains on service.
3) For a deposit held longer than eighteen (18) months, the deposit will be recalculated, at Customer’s request, and based on Customer’s actual usage. If the deposit on account differs from the recalculated amount by more than ten percent (10%), Company may collect any underpayment and shall refund any overpayment by check or credit to Customer's bill. No refund will be made if Customer's bill is delinquent at the time of the recalculation.
4) If Customer fails to maintain a satisfactory payment or credit record, or otherwise becomes a new or greater credit risk, as determined by Company in its sole discretion, Company may require a new or additional deposit from Customer.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 102.1

TERMS AND CONDITIONS

Deposits

RESIDENTIAL (continued)

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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DATE OF ISSUE: November 26, 2014

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 103

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to residential customers and to small commercial customers served under Rates CGS. Small business customers with combined gas and electric services must be served exclusively under General Service Rate GS for their electric service. Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in the plan at any time.

The budgeted amount will be determined by Company and will be based on one-twelfth of the customer's usage for either an actual or estimated twelve (12) months. The budgeted amount will be subject to review and adjustment by Company at any time during the customer's budget year. If actual usage indicates the customer's account will not be current with the final payment in the customer's budget year, the customer will be required to pay their Budget Payment Plan account to $0 prior to the beginning of the customer's next budget year.

If a customer fails to pay bills as agreed under the Budget Payment Plan, Company reserves the right to remove the customer from the plan, restore the customer to regular billing and require immediate payment of any deficiency. A customer removed from the Budget Payment Plan for non-payment may be prohibited from further participation in the Plan for twelve (12) months.

Failure to receive a bill in no way exempts a customer from the provisions of these terms and conditions.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 103

TERMS AND CONDITIONS

Budget Payment Plan

Company's Budget Payment Plan is available to residential customers and to small commercial customers served under Rates CGS. Small business customers with combined gas and electric services must be served exclusively under General Service Rate GS for their electric service. Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in the plan at any time.

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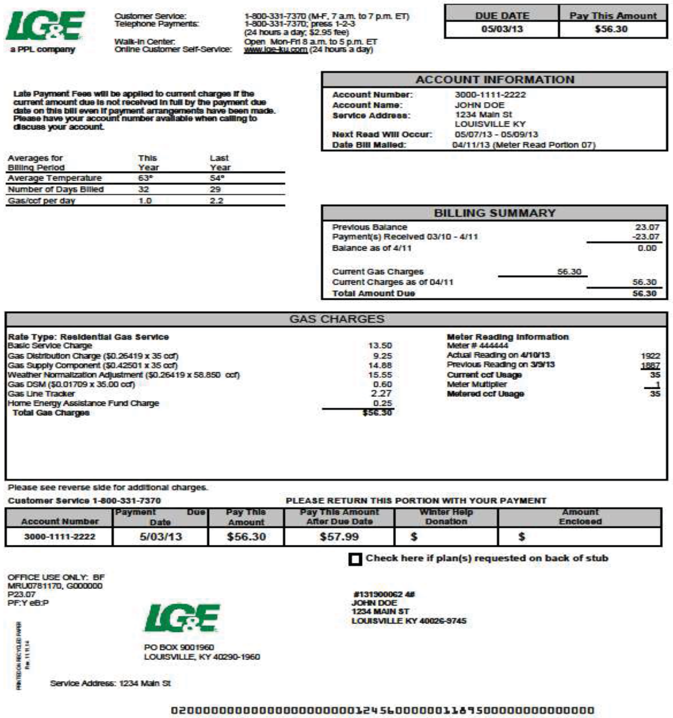
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

TERMS AND CONDITIONS

Bill Format



a PPL company

Customer Service: 1-800-331-7370 (M-F, 7 a.m. to 7 p.m. ET)
Telephone Payments: 1-800-331-7370; press 1-2-3 (24 hours a day; $2.95 fee)
Walk-In Center: Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service: www.lge-ku.com (24 hours a day)

DUE DATE	Pay This Amount
05/03/13	$56.30

Late Payment Fees will be applied to current charges if the current amount due is not received in full by the payment due date on this bill even if payment arrangements have been made. Please have your account number available when calling to discuss your account.

ACCOUNT INFORMATION

Account Number:	3000-1111-2222
Account Name:	JOHN DOE
Service Address:	1234 Main St LOUISVILLE KY
Next Read Will Occur:	05/07/13 - 05/09/13
Date Bill Mailed:	04/11/13 (Meter Read Portion 07)

Averages for Billing Period	This Year	Last Year
Average Temperature	63°	54°
Number of Days Billed	32	29
Gas/ccf per day	1.0	2.2

BILLING SUMMARY

Previous Balance		23.07
Payment(s) Received 03/10 - 4/11		-23.07
Balance as of 4/11		0.00
Current Gas Charges	56.30	
Current Charges as of 04/11		56.30
Total Amount Due		**56.30**

GAS CHARGES

Rate Type: Residential Gas Service

Basic Service Charge	13.50
Gas Distribution Charge ($0.26419 x 35 ccf)	9.25
Gas Supply Component ($0.42501 x 35 ccf)	14.88
Weather Normalization Adjustment ($0.26419 x 58.850 ccf)	15.55
Gas DSM ($0.01709 x 35.00 ccf)	0.60
Gas Line Tracker	2.27
Home Energy Assistance Fund Charge	0.25
Total Gas Charges	**$56.30**

Meter Reading Information

Meter # 444444	
Actual Reading on 4/10/13	1922
Previous Reading on 3/9/13	1887
Current ccf Usage	**35**
Meter Multiplier	1
Metered ccf Usage	**35**

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number	Payment Due Date	Pay This Amount	Pay This Amount After Due Date	Winter Help Donation	Amount Enclosed
3000-1111-2222	5/03/13	$56.30	$57.99	$	$

☐ **Check here if plan(s) requested on back of stub**

OFFICE USE ONLY: BF
MRU0781170, G000000
P23.07
PF:Y eB:P

PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900062 4#
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40026-9745

Service Address: 1234 Main St

020000000000000000000000124560000000118950000000000000000

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

TERMS AND CONDITIONS

Bill Format

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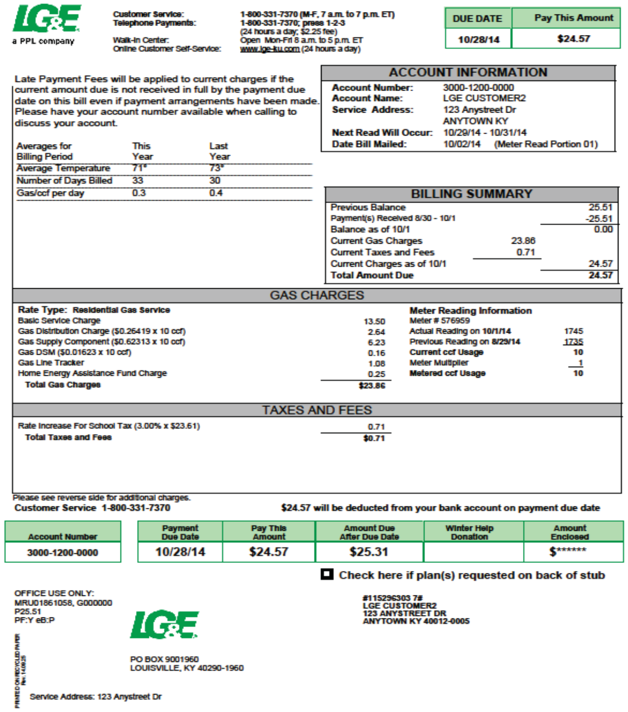


a PPL company

Customer Service: **1-800-331-7370 (M-F, 7 a.m. to 7 p.m. ET)**
Telephone Payments: **1-800-331-7370; press 1-2-3** (24 hours a day; $2.25 fee)
Walk-In Center: Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service: www.lge-ku.com (24 hours a day)

DUE DATE	Pay This Amount
10/28/14	$24.57

Late Payment Fees will be applied to current charges if the current amount due is not received in full by the payment due date on this bill even if payment arrangements have been made. Please have your account number available when calling to discuss your account.

ACCOUNT INFORMATION

Account Number:	3000-1200-0000
Account Name:	LGE CUSTOMER2
Service Address:	123 Anystreet Dr ANYTOWN KY
Next Read Will Occur:	10/29/14 - 10/31/14
Date Bill Mailed:	10/02/14 (Meter Read Portion 01)

Averages for Billing Period	This Year	Last Year
Average Temperature	71°	73°
Number of Days Billed	33	30
Gas/ccf per day	0.3	0.4

BILLING SUMMARY

Previous Balance		25.51
Payment(s) Received 8/30 - 10/1		-25.51
Balance as of 10/1		0.00
Current Gas Charges	23.86	
Current Taxes and Fees	0.71	
Current Charges as of 10/1		24.57
Total Amount Due		**24.57**

GAS CHARGES

Rate Type: Residential Gas Service

Basic Service Charge	13.50
Gas Distribution Charge ($0.26419 x 10 ccf)	2.64
Gas Supply Component ($0.62313 x 10 ccf)	6.23
Gas DSM ($0.01623 x 10 ccf)	0.16
Gas Line Tracker	1.08
Home Energy Assistance Fund Charge	0.25
Total Gas Charges	**$23.86**

Meter Reading Information

Meter # 576959	
Actual Reading on **10/1/14**	1745
Previous Reading on **8/29/14**	1735
Current ccf Usage	**10**
Meter Multiplier	1
Metered ccf Usage	**10**

TAXES AND FEES

Rate Increase For School Tax (3.00% x $23.61)	0.71
Total Taxes and Fees	**$0.71**

Please see reverse side for additional charges.

Customer Service 1-800-331-7370

$24.57 will be deducted from your bank account on payment due date

Account Number	Payment Due Date	Pay This Amount	Amount Due After Due Date	Winter Help Donation	Amount Enclosed
3000-1200-0000	10/28/14	$24.57	$25.31		$******

☐ **Check here if plan(s) requested on back of stub**

OFFICE USE ONLY:
MRU01861058, G000000
P25.51
PF:Y eB:P

PO BOX 9001960
LOUISVILLE, KY 40290-1960

#115296303 7#
LGE CUSTOMER2
123 ANYSTREET DR
ANYTOWN KY 40012-0005

Service Address: 123 Anystreet Dr

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

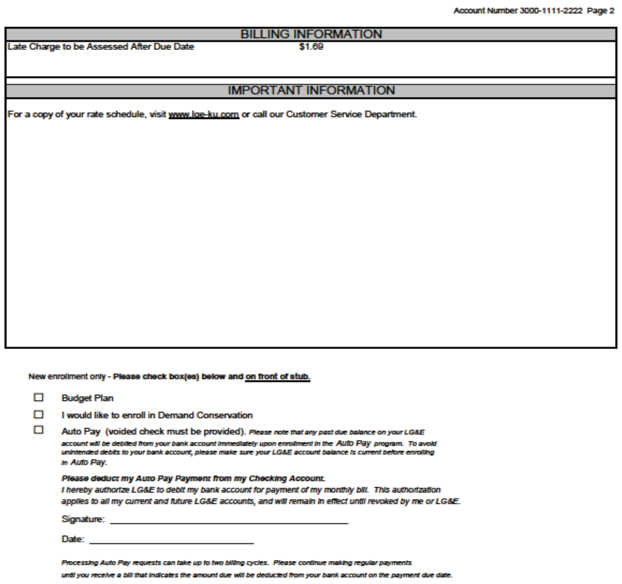
ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 104.1

TERMS AND CONDITIONS

Bill Format



Account Number 3000-1111-2222 Page 2

BILLING INFORMATION

Late Charge to be Assessed After Due Date $1.69

IMPORTANT INFORMATION

For a copy of your rate schedule, visit www.lge-ku.com or call our Customer Service Department.

New enrollment only - **Please check box(es) below and <u>on front of stub.</u>**

☐ Budget Plan

☐ I would like to enroll in Demand Conservation

☐ Auto Pay (voided check must be provided). *Please note that any past due balance on your LG&E account will be debited from your bank account immediately upon enrollment in the Auto Pay program. To avoid unintended debits to your bank account, please make sure your LG&E account balance is current before enrolling in Auto Pay.*

Please deduct my Auto Pay Payment from my Checking Account.
I hereby authorize LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

Signature: ______________________________

Date: ______________________

Processing Auto Pay requests can take up to two billing cycles. Please continue making regular payments until you receive a bill that indicates the amount due will be deducted from your bank account on the payment due date.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 104.1

TERMS AND CONDITIONS

Bill Format

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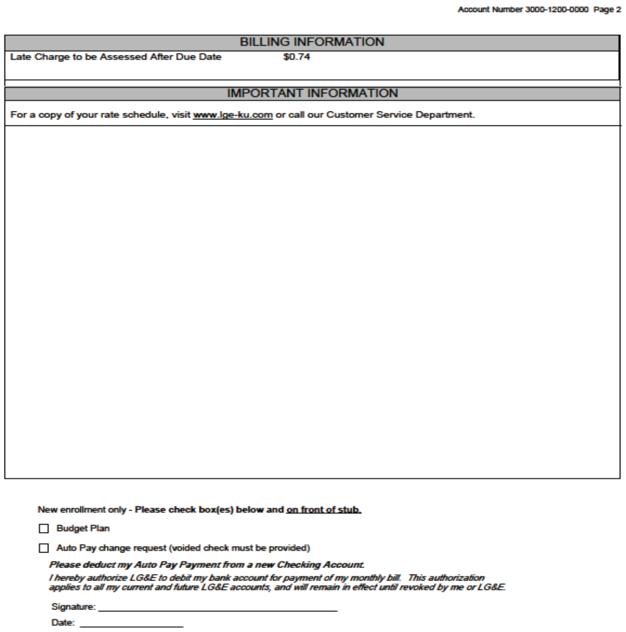


Account Number 3000-1200-0000 Page 2

BILLING INFORMATION

Late Charge to be Assessed After Due Date $0.74

IMPORTANT INFORMATION

For a copy of your rate schedule, visit www.lge-ku.com or call our Customer Service Department.

New enrollment only - **Please check box(es) below and <u>on front of stub.</u>**

☐ Budget Plan

☐ Auto Pay change request (voided check must be provided)

Please deduct my Auto Pay Payment from a new Checking Account.
I hereby authorize LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

Signature: ______________________________

Date: ________________

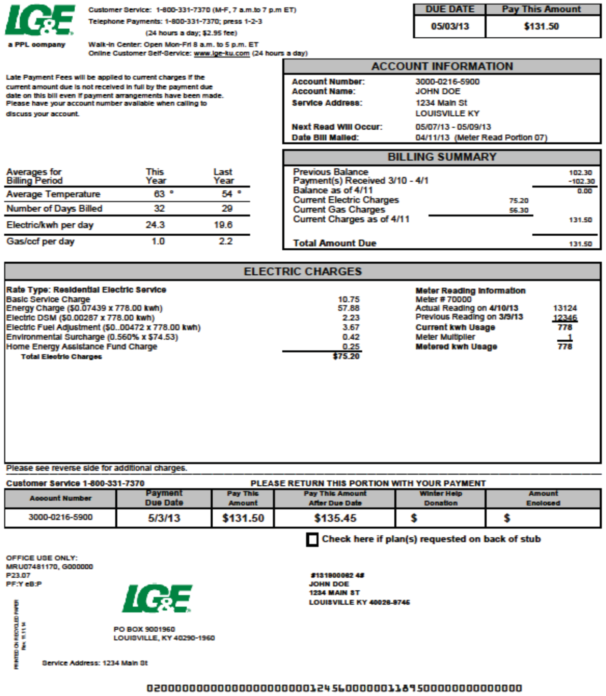
DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Bill Format



LG&E a PPL company

Customer Service: 1-800-331-7370 (M-F, 7 a.m.to 7 p.m ET)
Telephone Payments: 1-800-331-7370; press 1-2-3
(24 hours a day; $2.95 fee)
Walk-in Center: Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service: www.lge-ku.com (24 hours a day)

DUE DATE	Pay This Amount
05/03/13	$131.50

Late Payment Fees will be applied to current charges if the current amount due is not received in full by the payment due date on this bill even if payment arrangements have been made. Please have your account number available when calling to discuss your account.

ACCOUNT INFORMATION

Account Number: 3000-0216-5900
Account Name: JOHN DOE
Service Address: 1234 Main St
LOUISVILLE KY
Next Read Will Occur: 05/07/13 - 05/09/13
Date Bill Mailed: 04/11/13 (Meter Read Portion 07)

Averages for Billing Period	This Year	Last Year
Average Temperature	63 °	54 °
Number of Days Billed	32	29
Electric/kwh per day	24.3	19.6
Gas/ccf per day	1.0	2.2

BILLING SUMMARY

Previous Balance		102.30
Payment(s) Received 3/10 - 4/1		-102.30
Balance as of 4/11		0.00
Current Electric Charges	75.20	
Current Gas Charges	56.30	
Current Charges as of 4/11		131.50
Total Amount Due		131.50

ELECTRIC CHARGES

Rate Type: Residential Electric Service		**Meter Reading Information**	
Basic Service Charge	10.75	Meter # 70000	
Energy Charge ($0.07439 x 778.00 kwh)	57.88	Actual Reading on 4/10/13	13124
Electric DSM ($0.00287 x 778.00 kwh)	2.23	Previous Reading on 3/9/13	12346
Electric Fuel Adjustment ($0..00472 x 778.00 kwh)	3.67	**Current kwh Usage**	778
Environmental Surcharge (0.560% x $74.53)	0.42	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.25	**Metered kwh Usage**	778
Total Electric Charges	$75.20		

Please see reverse side for additional charges.

Customer Service 1-800-331-7370 **PLEASE RETURN THIS PORTION WITH YOUR PAYMENT**

Account Number	Payment Due Date	Pay This Amount	Pay This Amount After Due Date	Winter Help Donation	Amount Enclosed
3000-0216-5900	5/3/13	$131.50	$135.45	$	$

☐ Check here if plan(s) requested on back of stub

OFFICE USE ONLY:
MRU07481170, G000000
P23.07
PF:Y eB:P

LG&E
PO BOX 9001960
LOUISVILLE, KY 40290-1960

#131900082 4#
JOHN DOE
1234 MAIN ST
LOUISVILLE KY 40026-9745

PRINTED ON RECYCLED PAPER

Service Address: 1234 Main St

020000000000000000000000124560000001189500000000000000

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: /s/ Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

Bill Format

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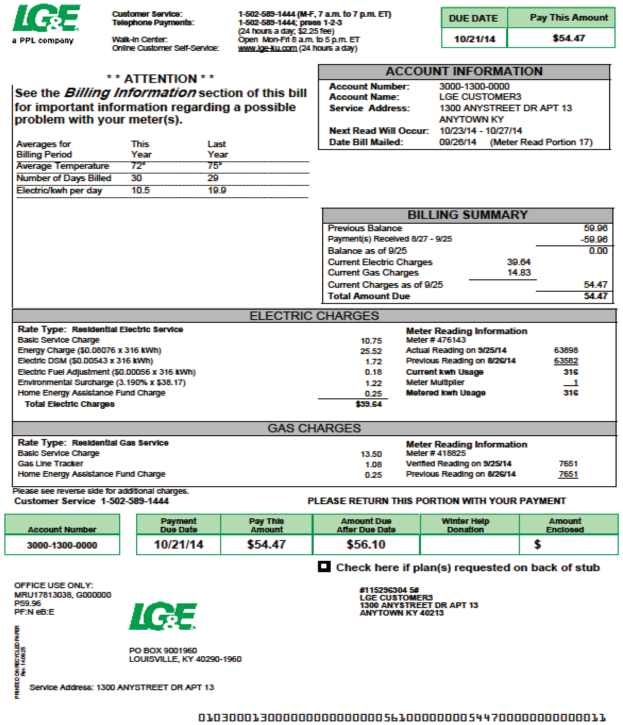


LG&E a PPL company

Customer Service: 1-502-589-1444 (M-F, 7 a.m. to 7 p.m. ET)
Telephone Payments: 1-502-589-1444; press 1-2-3
(24 hours a day; $2.25 fee)
Walk-In Center: Open Mon-Fri 8 a.m. to 5 p.m. ET
Online Customer Self-Service: www.lge-ku.com (24 hours a day)

DUE DATE	Pay This Amount
10/21/14	$54.47

* * ATTENTION * *

See the *Billing Information* section of this bill for important information regarding a possible problem with your meter(s).

Averages for Billing Period	This Year	Last Year
Average Temperature	72°	75°
Number of Days Billed	30	29
Electric/kwh per day	10.5	19.9

ACCOUNT INFORMATION

Account Number: 3000-1300-0000
Account Name: LGE CUSTOMER3
Service Address: 1300 ANYSTREET DR APT 13
ANYTOWN KY
Next Read Will Occur: 10/23/14 - 10/27/14
Date Bill Mailed: 09/26/14 (Meter Read Portion 17)

BILLING SUMMARY

Previous Balance		59.96
Payment(s) Received 8/27 - 9/25		-59.96
Balance as of 9/25		0.00
Current Electric Charges	39.64	
Current Gas Charges	14.83	
Current Charges as of 9/25		54.47
Total Amount Due		54.47

ELECTRIC CHARGES

Rate Type: Residential Electric Service		**Meter Reading Information**	
Basic Service Charge	10.75	Meter # 476143	
Energy Charge ($0.08076 x 316 kWh)	25.52	Actual Reading on 9/25/14	63898
Electric DSM ($0.00543 x 316 kWh)	1.72	Previous Reading on 8/26/14	63582
Electric Fuel Adjustment ($0.00056 x 316 kWh)	0.18	**Current kwh Usage**	316
Environmental Surcharge (3.190% x $38.17)	1.22	Meter Multiplier	1
Home Energy Assistance Fund Charge	0.25	**Metered kwh Usage**	316
Total Electric Charges	$39.64		

GAS CHARGES

Rate Type: Residential Gas Service		**Meter Reading Information**	
Basic Service Charge	13.50	Meter # 418825	
Gas Line Tracker	1.08	Verified Reading on 9/25/14	7651
Home Energy Assistance Fund Charge	0.25	Previous Reading on 8/26/14	7651

Please see reverse side for additional charges.

Customer Service 1-502-589-1444 **PLEASE RETURN THIS PORTION WITH YOUR PAYMENT**

Account Number	Payment Due Date	Pay This Amount	Amount Due After Due Date	Winter Help Donation	Amount Enclosed
3000-1300-0000	10/21/14	$54.47	$56.10		$

☐ Check here if plan(s) requested on back of stub

OFFICE USE ONLY:
MRU17813038, G000000
P59.96
PF:N eB:E

LG&E
PO BOX 9001960
LOUISVILLE, KY 40290-1960

#115296304 5#
LGE CUSTOMER3
1300 ANYSTREET DR APT 13
ANYTOWN KY 40213

PRINTED ON RECYCLED PAPER

Service Address: 1300 ANYSTREET DR APT 13

01030001300000000000000056100000000544700000000000011

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

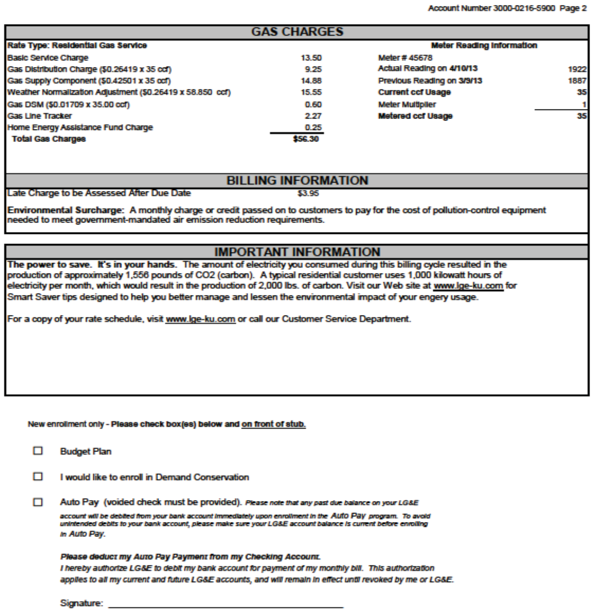
ISSUED BY: /s/ Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 104.3

TERMS AND CONDITIONS

Bill Format



Account Number 3000-0216-5900 Page 2

GAS CHARGES

Rate Type: Residential Gas Service		**Meter Reading Information**	
Basic Service Charge	13.50	Meter # 45678	
Gas Distribution Charge ($0.26419 x 35 ccf)	9.25	Actual Reading on 4/10/13	1922
Gas Supply Component ($0.42501 x 35 ccf)	14.88	Previous Reading on 3/9/13	1887
Weather Normalization Adjustment ($0.26419 x 58.850 ccf)	15.55	**Current ccf Usage**	**35**
Gas DSM ($0.01709 x 35.00 ccf)	0.60	Meter Multiplier	1
Gas Line Tracker	2.27	**Metered ccf Usage**	**35**
Home Energy Assistance Fund Charge	0.25		
Total Gas Charges	**$56.30**		

BILLING INFORMATION

Late Charge to be Assessed After Due Date $3.95

Environmental Surcharge: A monthly charge or credit passed on to customers to pay for the cost of pollution-control equipment needed to meet government-mandated air emission reduction requirements.

IMPORTANT INFORMATION

The power to save. It's in your hands. The amount of electricity you consumed during this billing cycle resulted in the production of approximately 1,556 pounds of CO2 (carbon). A typical residential customer uses 1,000 kilowatt hours of electricity per month, which would result in the production of 2,000 lbs. of carbon. Visit our Web site at www.lge-ku.com for Smart Saver tips designed to help you better manage and lessen the environmental impact of your engery usage.

For a copy of your rate schedule, visit www.lge-ku.com or call our Customer Service Department.

New enrollment only - **Please check box(es) below and on front of stub.**

☐ Budget Plan

☐ I would like to enroll in Demand Conservation

☐ Auto Pay (voided check must be provided). *Please note that any past due balance on your LG&E account will be debited from your bank account immediately upon enrollment in the Auto Pay program. To avoid unintended debits to your bank account, please make sure your LG&E account balance is current before enrolling in Auto Pay.*

Please deduct my Auto Pay Payment from my Checking Account.
I hereby authorize LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

Signature: ____________________

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: */s/* Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 104.3

TERMS AND CONDITIONS

Bill Format

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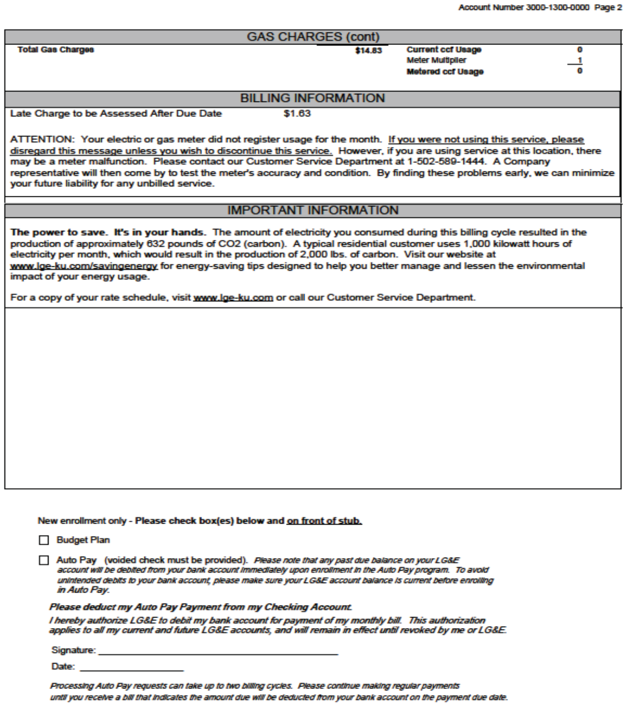

Account Number 3000-1300-0000 Page 2

GAS CHARGES (cont)

Total Gas Charges	**$14.83**	**Current ccf Usage**	**0**
		Meter Multiplier	1
		Metered ccf Usage	**0**

BILLING INFORMATION

Late Charge to be Assessed After Due Date $1.63

ATTENTION: Your electric or gas meter did not register usage for the month. If you were not using this service, please disregard this message unless you wish to discontinue this service. However, if you are using service at this location, there may be a meter malfunction. Please contact our Customer Service Department at 1-502-589-1444. A Company representative will then come by to test the meter's accuracy and condition. By finding these problems early, we can minimize your future liability for any unbilled service.

IMPORTANT INFORMATION

The power to save. It's in your hands. The amount of electricity you consumed during this billing cycle resulted in the production of approximately 632 pounds of CO2 (carbon). A typical residential customer uses 1,000 kilowatt hours of electricity per month, which would result in the production of 2,000 lbs. of carbon. Visit our website at www.lge-ku.com/savingenergy for energy-saving tips designed to help you better manage and lessen the environmental impact of your energy usage.

For a copy of your rate schedule, visit www.lge-ku.com or call our Customer Service Department.

New enrollment only - **Please check box(es) below and on front of stub.**

☐ Budget Plan

☐ Auto Pay (voided check must be provided). *Please note that any past due balance on your LG&E account will be debited from your bank account immediately upon enrollment in the Auto Pay program. To avoid unintended debits to your bank account, please make sure your LG&E account balance is current before enrolling in Auto Pay.*

Please deduct my Auto Pay Payment from my Checking Account.
I hereby authorize LG&E to debit my bank account for payment of my monthly bill. This authorization applies to all my current and future LG&E accounts, and will remain in effect until revoked by me or LG&E.

Signature: ____________________
Date: ____________

Processing Auto Pay requests can take up to two billing cycles. Please continue making regular payments until you receive a bill that indicates the amount due will be deducted from your bank account on the payment due date.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: */s/* Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 105
Canceling P.S.C. Gas No. 9, Original Sheet No. 105

TERMS AND CONDITIONS

Discontinuance of Service

In accordance with and subject to the rules and regulations of the Public Service Commission of Kentucky, Company shall have the right to refuse, or to discontinue, service to an applicant or customer under the following conditions:

A. When Company's or Commission's rules and regulations have not been complied with. However, service may be discontinued or refused only after Company has made a reasonable effort to induce Customer to comply with its rules and then only after Customer has been given at least 10 days written notice of such intention, mailed to his last known address.

B. When a dangerous condition is found to exist on Customer's or Applicant's premises. In such case service will be discontinued without notice or refused, as the case might be. Company will notify Customer or Applicant immediately of the reason for the discontinuance or refusal and the corrective action to be taken before service can be restored or initiated.

C. When Customer or Applicant refuses or neglects to provide reasonable access and/or easements to and on his premises for the purposes of installation, operation, meter reading, maintenance, or removal of Company's property. Customer shall be given 15 days written notice of Company's intention to discontinue or refuse service.

D. When Applicant is indebted to Company for service furnished. Company may refuse to serve until indebtedness is paid.

E. When Customer or Applicant does not comply with state, municipal or other codes, rules and regulations applying to such service.

F. When directed to do so by governmental authority.

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 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

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 4, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 105

TERMS AND CONDITIONS

Discontinuance of Service

In accordance with and subject to the rules and regulations of the Public Service Commission of Kentucky, Company shall have the right to refuse, or to discontinue, service to an applicant or customer under the following conditions:

A. When Company's or Commission's rules and regulations have not been complied with.
However, service may be discontinued or refused only after Company has made a
reasonable effort to induce Customer to comply with its rules and then only after Customer has
been given at least 10 days written notice of such intention, mailed or otherwise delivered, T
including, but not limited to, electronic mail, to Customer's last known address. T

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, T
operation, meter reading, maintenance, or removal of Company's property. Customer shall be
given 15 days written notice (either mailed or otherwise delivered, including, but not limited to, T
electronic mail), of Company's intention to discontinue or refuse service. T

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.

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 lapse in service will not be subject to

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 105.1
Canceling P.S.C. Gas No. 9, Original Sheet No. 105.1

TERMS AND CONDITIONS

Discontinuance of Service

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.

H. For non-payment of bills. Company shall have the right to discontinue service for non-payment of bills after Customer has been given at least ten days written notice separate from his original bill. Cut-off may be effected not less than twenty-seven (27) days after the mailing date of original bills unless, prior to discontinuance, a residential customer presents to Company a written certificate, signed by a physician, registered nurse, or public health officer, that such discontinuance will aggravate an existing illness or infirmity on the affected premises, in which case discontinuance may be effected not less than thirty (30) days from the original date of discontinuance. Company shall notify Customer, in writing, of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance.

I. For fraudulent or illegal use of service. When Company discovers evidence that by fraudulent or illegal means Customer has obtained unauthorized service or has diverted the service for unauthorized use or has obtained service without same being properly measured, the service to Customer may be discontinued without notice. Within twenty-four (24) hours after such termination, Company shall send written notification to Customer of the reasons for such discontinuance of service and of the customer's right to challenge the termination by filing a formal complaint with the Public Service Commission of Kentucky. Company's right of termination is separate from and in addition to any other legal remedies which the utility may pursue for illegal use or theft of service. Company shall not be required to restore service until Customer has complied with all rules of Company and regulations of the Commission and Company has been reimbursed for the estimated amount of the service rendered and the cost to Company incurred by reason of the fraudulent use.

When service has been discontinued for any of the above reasons, Company shall not be responsible for any damage that may result therefrom.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 105.1

TERMS AND CONDITIONS

Discontinuance of Service

disconnection unless: (1) such service was provided pursuant to a fraudulent application T
submitted by Customer; (2) Customer and Company have entered into a contractual agreement T
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
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health officer, that such discontinuance will aggravate an existing illness or infirmity on the
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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

TERMS AND CONDITIONS

Discontinuance of Service

Discontinuance or refusal of service shall be in addition to, and not in lieu of, any other rights or remedies available to Company.

Company may defer written notice based on Customer's payment history provided Company continues to provide the required ten (10) days written notice prior to discontinuance of service.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

TERMS AND CONDITIONS

Discontinuance of Service

When service has been discontinued for any of the above reasons, Company shall not be T
responsible for any damage that may result therefrom. T

Discontinuance or refusal of service shall be in addition to, and not in lieu of, any other rights or remedies available to Company.

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to, electronic mail), based on Customer's payment history provided Company continues to T
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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 106
Canceling P.S.C. Gas No. 9, Original Sheet No. 106

TERMS AND CONDITIONS

Gas Main Extension Rules

1. Company will extend its gas distribution mains at its own expense for a distance of one hundred (100) feet to each bona-fide applicant who agrees in writing to take service within one (1) year after the extension is completed and who has a suitable Customer's Service Line installed and ready for connection provided the following criteria are met:
    a) The existing main is of sufficient capacity to properly supply the additional customer(s);
    b) The customer(s) contracts to use gas on a continuous basis for one (1) year or more; and,
    c) The potential consumption and revenue will be of such amount and permanence as to warrant the capital expenditures involved to make the investment economically feasible.

2. Company will extend its gas mains in excess of the above distance provided the applicant for service advances to Company an amount equal to the estimated cost of such excess portion of the extension. Company shall have the right to determine the length of the extension and to specify the pipe size and location of the extension, as well as the timing of its construction.

3. Where funds were advanced in accordance with paragraph 2 for extensions into developed residential neighborhoods and notwithstanding paragraph 1, any customer that subsequently connects to the main during a ten-year period from the effective date of the main extension contract shall advance to Company a pro rata share of the cost of the extension over 100 feet per connected customer.

4. For each new year-round customer connected to an extension in accordance with paragraph 3, Company will refund to the previous applicant(s) who advanced funds an amount equal to the difference between the refundable amount advanced and the amount of the advance so determined for the new applicant.

5. Company will extend its gas mains to serve a proposed real estate subdivision provided the applicant for such extension advances to Company an amount equal to the estimated cost of the total extension. Company shall have the right to determine the length of the extension and to specify the pipe size and the location of the extension, as well as the timing of its construction.

6. For each new year-round customer actually connected to the extension within a ten-year period following the effective date of the gas main extension contract, but not to extensions or laterals therefrom, Company will refund to applicant(s) who advanced funds in accordance with paragraph 5 above an amount equal to 100 times the average unit cost per foot of extension advanced by such applicant(s); provided that such refunds shall not exceed, in the aggregate, the amount originally advanced to Company.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 106

TERMS AND CONDITIONS

Gas Main Extension Rules

1. Company will extend its gas distribution mains at its own expense for a distance of one hundred (100) feet to each bona-fide applicant who agrees in writing to take service within one (1) year after the extension is completed and who has a suitable Customer's Service Line installed and ready for connection provided the following criteria are met:
    a) The existing main is of sufficient capacity to properly supply the additional customer(s);
    b) The customer(s) contracts to use gas on a continuous basis for one (1) year or more; and,
    c) The potential consumption and revenue will be of such amount and permanence as to warrant the capital expenditures involved to make the investment economically feasible.

2. Company will extend its gas mains in excess of the above distance provided the applicant for service advances to Company an amount equal to the estimated cost of such excess portion of the extension. Company shall have the right to determine the length of the extension and to specify the pipe size and location of the extension, as well as the timing of its construction.

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 106.1
Canceling P.S.C. Gas No. 9, Original Sheet No. 106.1

TERMS AND CONDITIONS

Gas Main Extension Rules

7. Company will install at its own expense a service pipe of suitable capacity extending from its gas main to the customer's property line beyond which point all necessary piping shall be installed by and at the expense of the customer and in a manner acceptable to Company.

8. Company will install at its own expense the necessary meter together with the regulator required to convert from medium pressure to service pressure. When a high pressure gas line is tapped to serve a customer or group of customers, Company may charge the customer or customers for the estimated installed cost of the tap, any regulation equipment, piping, and any other equipment or facilities determined by Company, in its sole discretion, to be necessary to provide such service consistent with good operating practice.

9. In the event Company is required to make a further extension of its mains to serve a customer, Company reserves the right to tap any extension constructed under these rules and to make connections from such additional extensions without application of the refunds referred to in paragraph 4 or 6 above.

10. The title to all extensions herein provided for, together with all necessary rights-of-way, permits and easements, shall be and remain in Company.

11. Company shall not be obligated to make service connections or to extend its gas mains in cases where such extensions or connections, in the sole judgment of Company would be infeasible, impractical, or contrary to good operating practice, or where such extensions are not in accordance with the terms of the applicable rate schedule.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 106.1

TERMS AND CONDITIONS

Gas Main Extension Rules

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: August 1, 2010

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

Gas Service Restrictions

By Order dated September 5, 1973, in Case Nos. 5829 and 5839, the Public Service Commission of Kentucky authorized Company to incorporate in its gas tariff restrictions on the supply of gas service, occasioned by the inadequacy of gas supplies to meet customer demands. These restrictions have been modified from time to time by tariff filings authorized or approved by the Commission. Uncertainty as to future gas supply makes it necessary that Company continue to exercise control over the addition of gas loads to its system, as set forth in these rules.

1. **GENERAL**. Except as specifically provided in these rules, Company will not (a) initiate service to any new customer, location, or service point; (b) permit any commercial customer (including any governmental agency or institution) or any industrial customer to increase its connected load or to expand its gas requirements in any manner; or (c) permit any customer to change to another rate schedule for the purpose of obtaining a higher priority under Company's Tariff.

2. **NEW CUSTOMERS**. Until further notice, Company will accept applications for gas service to new customers as set forth below. Main extensions will be made in accordance with the Gas Main Extension Rules contained in this Tariff.

   (a) **FOR SERVICE UNDER RATES RGS, VFD, CGS, DGGS, IGS, and FT**. Single family dwelling units individually metered. Commercial and industrial customers and multi-family residences served through a single meter. Company will have the right to limit the total connected load to a maximum of 8,000 cubic feet per hour, when in Company's judgment such is necessary in order to enable it to continue to supply reliable service to existing customers.

   (b) **FOR SERVICE UNDER OTHER RATE SCHEDULES**. Company may undertake to serve new customers with requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS, IGS, and FT when in its judgment actual and potential gas supplies are sufficient to enable it to do so. Company will designate the applicable rate schedule under which such service will be supplied.

3. **INCREASE IN SERVICE TO EXISTING CUSTOMERS**. Until further notice, Company will, upon application, permit increases in the connected gas load or the gas usage of commercial and industrial customers existing as of the effective date of these rules, as follows:

   (a) **ADDITIONAL SERVICE UNDER RATES RGS, VFD, CGS, DGGS, IGS, and FT.** Company will permit the addition of connected gas loads under Rates RGS, VFD, CGS, DGGS, IGS, and FT. Company will have the right to limit the total connected load to a maximum of 8,000 cubic feet per hour, when in Company's judgment such is necessary in order to enable it to continue to supply reliable service to existing customers.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

TERMS AND CONDITIONS

Gas Service Restrictions

By Order dated September 5, 1973, in Case Nos. 5829 and 5839, the Public Service Commission of Kentucky authorized Company to incorporate in its gas tariff restrictions on the supply of gas service, occasioned by the inadequacy of gas supplies to meet customer demands. These restrictions have been modified from time to time by tariff filings authorized or approved by the Commission. Uncertainty as to future gas supply makes it necessary that Company continue to exercise control over the addition of gas loads to its system, as set forth in these rules.

1. **GENERAL**. Except as specifically provided in these rules, Company will not (a) initiate service to any new customer, location, or service point; (b) permit any commercial customer (including any governmental agency or institution) or any industrial customer to increase its connected load or to expand its gas requirements in any manner; or (c) permit any customer to change to another rate schedule for the purpose of obtaining a higher priority under Company's Tariff.

2. **NEW CUSTOMERS**. Until further notice, Company will accept applications for gas service to new customers as set forth below. Main extensions will be made in accordance with the Gas Main Extension Rules contained in this Tariff.

   (a) **FOR SERVICE UNDER RATES RGS, VFD, CGS, DGGS, IGS, and FT**. Single family dwelling units individually metered. Commercial and industrial customers and multi-family residences served through a single meter. Company will have the right to limit the total connected load to a maximum of 8,000 cubic feet per hour, when in Company's judgment such is necessary in order to enable it to continue to supply reliable service to existing customers.

   (b) **FOR SERVICE UNDER OTHER RATE SCHEDULES**. Company may undertake to serve new customers with requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS, IGS, and FT when in its judgment actual and potential gas supplies are sufficient to enable it to do so. Company will designate the applicable rate schedule under which such service will be supplied.

3. **INCREASE IN SERVICE TO EXISTING CUSTOMERS**. Until further notice, Company will, upon application, permit increases in the connected gas load or the gas usage of commercial and industrial customers existing as of the effective date of these rules, as follows:

   (a) **ADDITIONAL SERVICE UNDER RATES RGS, VFD, CGS, DGGS, IGS, and FT.** Company will permit the addition of connected gas loads under Rates RGS, VFD, CGS, DGGS, IGS, and FT. Company will have the right to limit the total connected load to a maximum of 8,000 cubic feet per hour, when in Company's judgment such is necessary in order to enable it to continue to supply reliable service to existing customers.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010**

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 107.1
Canceling P.S.C. Gas No. 9, Original Sheet No. 107.1

TERMS AND CONDITIONS

Gas Service Restrictions

(b) **ADDITIONAL SERVICE UNDER OTHER RATE SCHEDULES**. Company may undertake to serve existing customers with additional requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS, IGS, and FT when in its judgment actual and potential gas supplies are sufficient to enable it to do so. Company will designate the applicable rate schedule under which such service will be supplied.

4. **LOAD ADDITIONS TO BE AGGREGATED**. Limitations on new or additional gas loads as specified herein refer to the aggregate of loads added subsequent to the effective date of these rules, and not to individual increments made from time to time.

5. **VOLUMES OF GAS USAGE**. Daily and monthly volumes of gas usage may be established or increased to reflect additions of connected load or increased usage of connected load existing as of the effective date of these rules. For customers subject to curtailment under Company's Curtailment Rules, Monthly Base Period Volumes will be established or adjusted accordingly.

6. **TRANSFERS BETWEEN LOCATIONS**. Company may permit any customer to transfer his own gas entitlement from one location to another; provided, however, that transfers of service cannot be aggregated so as to exceed the limitations on connected load set forth in Paragraphs 2 and 3 above with respect to Rates RGS, VFD, CGS, DGGS, IGS, and FT.

7. **PRIORITY CONSIDERATIONS**. If at any time, Company is required to select among applicants for service as provided for in Paragraphs 2(b) or 3(b) above, it will, to the extent practicable, observe the following priorities in the order named:

   (a) Schools, hospitals and similar institutions.
   (b) Other commercial establishments.
   (c) Industrial process and feedstock uses.
   (d) Other industrial applications.

8. **LAPSE OF APPLICATIONS**. If any applicant for new or increased service under these rules is not ready to take such service within twelve (12) months from the date of application, such application shall be void. Any reapplication shall be subject to Company's rules in effect at the time thereof.

9. Applicants may make application for gas service beyond that provided for in these rules, to be initiated at such time as these rules may be terminated or modified so as to enable Company to provide the service applied for. Company will file such applications in the order of receipt and dispose of them as circumstances dictate.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 107.1

TERMS AND CONDITIONS

Gas Service Restrictions

(b) **ADDITIONAL SERVICE UNDER OTHER RATE SCHEDULES**. Company may undertake to serve existing customers with additional requirements in excess of those allowable under Rates RGS, VFD, CGS, DGGS, IGS, and FT when in its judgment actual and potential gas supplies are sufficient to enable it to do so. Company will designate the applicable rate schedule under which such service will be supplied.

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: February 6, 2009

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2009-00549 dated July 30, 2010

TERMS AND CONDITIONS

Curtailment Rules

These rules are established to govern Company's available supply of gas to sales and transportation customers during periods of shortage or substantial reduction in the gas available to Company. These rules are designed to provide for curtailment or discontinuance of service made necessary by a deficiency in gas supply, capacity, or unforeseen emergency circumstances. These rules are designed to enable Company to continue to supply reliable gas service for residential and other human welfare purposes. These rules shall apply and continue in effect until lawfully modified or superseded under the regulatory jurisdiction of the Public Service Commission of Kentucky.

1. **DEFINITIONS** (for purposes of these Rules).

COMMERCIAL CUSTOMERS: Customers engaged primarily in the sale of goods or services, including institutions and local, state and Federal governmental agencies, for uses other than those involving manufacturing as further described in Rate CGS.

HUMAN NEEDS: Residential and other customers whose facilities are used for residential dwellings on either a permanent or temporary basis or a facility providing critical emergency services (including, but not limited to, apartment buildings, correctional institutions, hospitals, nursing homes, assisted living facilities, hotels, motels, fire department stations, police stations, national guard facilities, and emergency response agency facilities).

INDUSTRIAL CUSTOMERS: Customers engaged primarily in a process or processes which create or change raw or unfinished materials into another form or product, including, but not limited to, the generation of electric power as further described in Rate IGS and Rate DGGS.

SMALL INDUSTRIAL CUSTOMER: Any industrial customer whose aggregate of twelve Monthly Base Period Volumes is 10,000 Mcf or less.

LARGE INDUSTRIAL CUSTOMER: Any industrial customer whose aggregate of twelve Monthly Base Period Volumes exceeds 10,000 Mcf.

PILOT LIGHT REQUIREMENTS: Gas used on either a continuous or intermittent basis only for the ignition of the fuel in the main burner; does not include any gas used to preheat or atomize solid or liquid fuels.

BASE PERIOD: The twelve (12) months ending on the October 31 preceding the calendar year which is the subject of the implementation of any curtailments hereunder.

DATE OF ISSUE: January 31, 2013

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ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

TERMS AND CONDITIONS

Curtailment Rules

These rules are established to govern Company's available supply of gas to sales and transportation customers during periods of shortage or substantial reduction in the gas available to Company. These rules are designed to provide for curtailment or discontinuance of service made necessary by a deficiency in gas supply, capacity, or unforeseen emergency circumstances. These rules are designed to enable Company to continue to supply reliable gas service for residential and other human welfare purposes. These rules shall apply and continue in effect until lawfully modified or superseded under the regulatory jurisdiction of the Public Service Commission of Kentucky.

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COMMERCIAL CUSTOMERS: Customers engaged primarily in the sale of goods or services, including institutions and local, state and Federal governmental agencies, for uses other than those involving manufacturing as further described in Rate CGS.

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DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 108.1
Canceling P.S.C. Gas No. 9, Original Sheet No. 108.1

TERMS AND CONDITIONS

Curtailment Rules

MONTHLY BASE PERIOD VOLUMES: Monthly volumes assigned to each customer determined from its gas consumption (including sales and transportation volumes) during the Base Period.

AUTHORIZED MONTHLY VOLUME: The volume of gas authorized to be taken during a month and determined by deducting from the Monthly Base Period Volume the curtailment amount applicable for the month.

Some customers may have usage falling within more than one (1) of the above categories; as such, these customers may be required to segregate their total usage accordingly.

2. **COMBINATION OF AUTHORIZED MONTHLY VOLUMES**. Subject to a written application by a customer and acceptance thereof by Company, Company may permit any customer served through more than one point of delivery at any location, or any person, corporation or entity served with gas at more than one location, to take gas through the points or at the locations of its choosing, provided that the gas so taken will not exceed the combined Authorized Monthly Volumes applicable to such points of delivery, and provided that only volumes purchased under rate schedules subject to Pro-Rata Curtailment may be so combined. Gas taken through each individual point of delivery will be billed at the rate applicable to such point of delivery.

   The right to combine Authorized Monthly Volumes as herein described is limited to individual customers or individual persons, corporations or entities and such right will not extend to similar combinations between or among unrelated customers. Nor shall such combinations be employed by any customer for the purpose of obtaining a lower overall cost of gas.

   Provided, however, in the case of Industrial Customers provided with sales service under Rate IGS or Special Contracts, which have requested and received approval to combine Authorized Monthly Volumes, Monthly Base Period Volumes for such combined Industrial Customers must aggregate to not less than 10,000 Mcf for a twelve-month period and such combination shall be treated as a Large Industrial Customer for the purpose of implementing either Pro-Rata or Emergency Curtailment.

   For the purpose of assessment of penalties, the point of delivery will be considered on a combined basis, so that the actual combined takes will be measured against combined Authorized Monthly Volumes. It will be the responsibility of any applicant for this treatment to advise Company in writing as to the party or entity to be held accountable for the payment of such penalty.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
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Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 108.1

TERMS AND CONDITIONS

Curtailment Rules

MONTHLY BASE PERIOD VOLUMES: Monthly volumes assigned to each customer determined from its gas consumption (including sales and transportation volumes) during the Base Period.

AUTHORIZED MONTHLY VOLUME: The volume of gas authorized to be taken during a month and determined by deducting from the Monthly Base Period Volume the curtailment amount applicable for the month.

Some customers may have usage falling within more than one (1) of the above categories; as such, these customers may be required to segregate their total usage accordingly.

2. **COMBINATION OF AUTHORIZED MONTHLY VOLUMES**. Subject to a written application by a customer and acceptance thereof by Company, Company may permit any customer served through more than one point of delivery at any location, or any person, corporation or entity served with gas at more than one location, to take gas through the points or at the locations of its choosing, provided that the gas so taken will not exceed the combined Authorized Monthly Volumes applicable to such points of delivery, and provided that only volumes purchased under rate schedules subject to Pro-Rata Curtailment may be so combined. Gas taken through each individual point of delivery will be billed at the rate applicable to such point of delivery.

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ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

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Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 108.2
Canceling P.S.C. Gas No. 9, Original Sheet No. 108.2

TERMS AND CONDITIONS

Curtailment Rules

3. PRO-RATA CURTAILMENT. In order to meet seasonal and daily sendout requirements, to preserve underground storage deliverability, and to provide for adequate and timely underground storage injections, Company will implement pro-rata curtailment with respect to the classes of customers here listed:

(a) All customers served under Rate AAGS.
(b) Large Industrial Customers provided with sales service under Rate IGS or Special Contracts.

Company will assign Monthly Base Period Volumes to each customer in the above two classes. Except in the case of an Emergency Curtailment, Company will provide as much notice as practicable to each of these customers that curtailment is being implemented. Such notice will include the percentage curtailment applicable to customer's Monthly Base Period Volume and the Authorized Monthly Volume such customer is authorized to take during said billing period.

Except in the case of Emergency Curtailment, such Pro-Rata Curtailment may only be implemented after Company issues an Operational Flow Order to customers served under Rate FT and takes similar actions applicable to transportation customers served under Special Contracts.

During each month, Pro-Rata Curtailment will be first applied to Rate AAGS customers until such curtailment reaches 100% of Monthly Base Period Volumes (allowing, however, for continuation of Pilot Light Requirements used in connection with alternate fuels). When Rate AAGS customers are 100% curtailed, any additional curtailment required will be apportioned at a uniform percentage to other customers subject to pro-rata curtailment under this Section 3.

4. **EMERGENCY CURTAILMENT**. In the event of an emergency, Company will initiate the following actions, individually or in combination, in the order necessary as time permits so that service may continue to be supplied for residential and other human health, safety and welfare needs.

(1) Issue Operational Flow Orders to customers served under Rate FT, and take similar actions applicable to transportation customers served under Special Contracts. Customers that fail to comply with Operational Flow Orders will be required to discontinue the use of natural gas.

(2) Issue Action Alerts to Pool Managers under Rider PS-TS-2 serving customers under Rider TS-2, and take similar actions applicable to transportation customers served under Special Contracts. Customers of Pool Managers that fail to comply with Action Alerts may be required to terminate service under Rider PS-TS-2 and Rider TS-2 and return to firm sales service.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 108.2

TERMS AND CONDITIONS

Curtailment Rules

3. PRO-RATA CURTAILMENT. In order to meet seasonal and daily sendout requirements, to preserve underground storage deliverability, and to provide for adequate and timely underground storage injections, Company will implement pro-rata curtailment with respect to the classes of customers here listed:

(a) All customers served under Rate AAGS.
(b) Large Industrial Customers provided with sales service under Rate IGS or Special Contracts.

Company will assign Monthly Base Period Volumes to each customer in the above two classes. Except in the case of an Emergency Curtailment, Company will provide as much notice as practicable to each of these customers that curtailment is being implemented. Such notice will include the percentage curtailment applicable to customer's Monthly Base Period Volume and the Authorized Monthly Volume such customer is authorized to take during said billing period.

Except in the case of Emergency Curtailment, such Pro-Rata Curtailment may only be implemented after Company issues an Operational Flow Order to customers served under Rate FT and takes similar actions applicable to transportation customers served under Special Contracts.

During each month, Pro-Rata Curtailment will be first applied to Rate AAGS customers until such curtailment reaches 100% of Monthly Base Period Volumes (allowing, however, for continuation of Pilot Light Requirements used in connection with alternate fuels). When Rate AAGS customers are 100% curtailed, any additional curtailment required will be apportioned at a uniform percentage to other customers subject to pro-rata curtailment under this Section 3.

4. **EMERGENCY CURTAILMENT**. In the event of an emergency, Company will initiate the following actions, individually or in combination, in the order necessary as time permits so that service may continue to be supplied for residential and other human health, safety and welfare needs.

(1) Issue Operational Flow Orders to customers served under Rate FT, and take similar actions applicable to transportation customers served under Special Contracts. Customers that fail to comply with Operational Flow Orders will be required to discontinue the use of natural gas.

(2) Issue Action Alerts to Pool Managers under Rider PS-TS-2 serving customers under Rider TS-2, and take similar actions applicable to transportation customers served under Special Contracts. Customers of Pool Managers that fail to comply with Action Alerts may be required to terminate service under Rider PS-TS-2 and Rider TS-2 and return to firm sales service.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No. 9, First Revision of Original Sheet No. 108.3
Canceling P.S.C. Gas No. 9, Original Sheet No. 108.3

TERMS AND CONDITIONS

Curtailment Rules

(3) Discontinue service to customers served under Rate AAGS.

(4) Implement curtailment of all or a portion of the gas usage by Large Industrial Customers served under either Rate IGS or Special Contracts for gas sales service.

(5) Once curtailment in level 4 (above) has reached 100% of usage (excluding Pilot Light Requirements), implement curtailment of all or a portion of gas usage to the remaining Small Industrial and non-human needs commercial use customers.

(6) Company may request that transportation customers served under Rate FT and Special Contracts allow Company's use of customer-owned gas to supply higher priority end-use customers. Company shall negotiate compensation for such gas with any customer that complies with such request.

(7) Once curtailment of customers in level 5 (above) has reached 100% of usage (excluding Pilot Light Requirements), request reduction of gas usage by human needs commercial, residential, and other human needs customers.

(8) Implement forced curtailment of gas usage through the isolation of gas distribution load centers from the gas distribution system network.

5. **PENALTY CHARGES**. Company may, in its sole discretion, apply a penalty for all gas taken during a period of either Pro-Rata or Emergency Curtailment.

Any customer subject to Pro-Rata curtailment in accordance with Section 3 above, who at the end of a month has taken gas in excess of its Authorized Monthly Volumes (excluding Pilot Light Requirements where applicable) for such month, may, in the sole discretion of Company, be subject to a penalty charge applicable to such excess takes of gas at the rate of $15.00 per Mcf plus the highest daily mid-point price posted in "*Platts Gas Daily*" for Dominion-South Point during each month of the period of curtailment, such penalty to be in addition to the established rate for service.

Any customer subject to Emergency Curtailment in accordance with Section 4 above, who uses quantities of gas in excess of authorized quantities (excluding Pilot Light Requirements where applicable) during a period of such Emergency Curtailment, may, in the sole discretion of Company, be subject to a penalty charge applicable to such unauthorized takes of gas at the rate of $15.00 per Mcf plus the highest daily mid-point price posted in "*Platts Gas Daily*" for Dominion-South Point during each month of the period of curtailment, such penalty to be in addition to the established rate for service.

DATE OF ISSUE: January 31, 2013

DATE EFFECTIVE: January 1, 2013

ISSUED BY: ***/s/*** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
2012-00222 dated December 20, 2012

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 108.3

TERMS AND CONDITIONS

Curtailment Rules

(3) Discontinue service to customers served under Rate AAGS.

(4) Implement curtailment of all or a portion of the gas usage by Large Industrial Customers served under either Rate IGS or Special Contracts for gas sales service.

(5) Once curtailment in level 4 (above) has reached 100% of usage (excluding Pilot Light Requirements), implement curtailment of all or a portion of gas usage to the remaining Small Industrial and non-human needs commercial use customers.

(6) Company may request that transportation customers served under Rate FT and Special Contracts allow Company's use of customer-owned gas to supply higher priority end-use customers. Company shall negotiate compensation for such gas with any customer that complies with such request.

(7) Once curtailment of customers in level 5 (above) has reached 100% of usage (excluding Pilot Light Requirements), request reduction of gas usage by human needs commercial, residential, and other human needs customers.

(8) Implement forced curtailment of gas usage through the isolation of gas distribution load centers from the gas distribution system network.

5. **PENALTY CHARGES**. Company may, in its sole discretion, apply a penalty for all gas taken during a period of either Pro-Rata or Emergency Curtailment.

Any customer subject to Pro-Rata curtailment in accordance with Section 3 above, who at the end of a month has taken gas in excess of its Authorized Monthly Volumes (excluding Pilot Light Requirements where applicable) for such month, may, in the sole discretion of Company, be subject to a penalty charge applicable to such excess takes of gas at the rate of $15.00 per Mcf plus the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment. Such penalty shall be in addition to the established rate for service. T

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ISSUED BY: ***/s/*** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company

P.S.C. Gas No. 9, Original Sheet No. 108.4

TERMS AND CONDITIONS

Curtailment Rules

The payment of penalty charges for takes of gas in excess of Authorized Monthly Volumes or authorized quantities shall not be considered as giving any customer the right to make unauthorized takes of gas, nor shall such penalty charges be considered as a substitute for any other remedy available to Company.

Company shall return to all customers through Company's Gas Supply Clause any penalty charges collected from customers under this Section 5 net of any penalty charges incurred from Company's supplier(s).

6. **DISCONTINUANCE OF SERVICE.** If any customer subject to curtailment under these rules fails to limit its use of gas as provided for herein, then Company shall have the right to immediately discontinue all gas supply to such customer.

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DATE EFFECTIVE: January 1, 2013

ISSUED BY: **/s/** Lonnie E. Bellar, Vice President
State Regulation and Rates
Louisville, Kentucky

**Issued by Authority of an Order of the
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2012-00222 dated December 20, 2012**

Louisville Gas and Electric Company

P.S.C. Gas No.10, Original Sheet No. 108.4

TERMS AND CONDITIONS

Curtailment Rules

Any customer subject to Emergency Curtailment in accordance with Section 4 above, who uses quantities of gas in excess of authorized quantities (excluding Pilot Light Requirements where applicable) during a period of such Emergency Curtailment, may, in the sole discretion of Company, be subject to a penalty charge applicable to such unauthorized takes of gas at the rate of $15.00 per Mcf plus the higher of the following: either (a) the highest daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment, or (b) the highest daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment. Such penalty shall be in addition to the established rate for service. T

The payment of penalty charges for takes of gas in excess of Authorized Monthly Volumes or authorized quantities shall not be considered as giving any customer the right to make unauthorized takes of gas, nor shall such penalty charges be considered as a substitute for any other remedy available to Company.

Company shall return to all customers through Company's Gas Supply Clause any penalty charges collected from customers under this Section 5 net of any penalty charges incurred from Company's supplier(s).

6. **DISCONTINUANCE OF SERVICE.** If any customer subject to curtailment under these rules fails to limit its use of gas as provided for herein, then Company shall have the right to immediately discontinue all gas supply to such customer.

DATE OF ISSUE: November 26, 2014

DATE EFFECTIVE: January 1, 2015

ISSUED BY: **/s/** Edwin R. Staton, Vice President
State Regulation and Rates
Louisville, Kentucky

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(5)
Sponsoring Witness: Edwin R. Staton

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.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

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 Edwin "Ed" R. Staton, Vice President, State Regulation and Rates, for Louisville Gas and Electric Company ("LG&E" or "Company"), a utility furnishing retail electric and gas service within the Commonwealth of Kentucky, which, on the 26th day of November, 2014, filed an application with the Kentucky Public Service Commission for the approval of an adjustment of the electric and gas rates, terms, conditions and tariffs of LG&E, and that notice to the public of the issuing of the same is being given in all respects as required by 807 KAR 5:001, Section 17 and 807 KAR 5:011, Sections 8(2)(c) and 9(2), as follows:

On the 26th day of November, 2014, the notice to the public was delivered for exhibition and public inspection at 820 West Broadway, Louisville, KY 40202 and that the same will be kept open to public inspection at said office in conformity with the requirements of 807 KAR 5:001, Section 17(1)(a) and 807 KAR 5:011, Section 8(1)(a).

I further certify that more than twenty (20) customers will be affected by said change by way of an increase in their rates or charges, and that on the 5th day of November, 2014, there was delivered to the Kentucky Press Association, an agency that acts on behalf of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, for publication therein once a week for three consecutive weeks beginning on November 19, 2014, a notice of the filing of LG&E's application, including its proposed rates, a copy of said notice being attached hereto as Exhibit A, and a list of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, a copy of said list being attached hereto as Exhibit B. A certificate of publication of said notice will be furnished to the Kentucky Public Service Commission upon completion of same pursuant to 807 KAR 5:001, Section 17(3)(b).

In addition, beginning on November 26, 2014, LG&E began including a general statement explaining the Application in this case with the bills for all Kentucky retail customers during the course of their regular monthly billing cycle. An accurate copy of this general statement is attached as Exhibit C.

Also beginning on November 19, 2014, LG&E posted on its Internet website a copy of the notice to the public and a hyperlink to the location on the Kentucky Public Service Commission's website where the case documents and tariff filings are available. Beginning on November 26, 2014, LG&E posted on its Internet website a complete copy of LG&E's application in this case. Both the notice being published in newspapers and the bill inserts being sent to customers include the web address to the online posting.

Given under my hand this 26th day of November, 2014.

Edwin "Ed" R. Staton
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 26th day of November, 2014.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
July 11, 2018

Exhibit A

Notice of the Filing

NOTICE

Notice is hereby given that, in a November 26, 2014 Application, Louisville Gas and Electric Company is seeking approval by the Public Service Commission, Frankfort, Kentucky of an adjustment of electric and gas rates and charges proposed to become effective on and after January 1, 2015.

LG&E CURRENT AND PROPOSED ELECTRIC RATES

Residential Service - Rate RS

	Current	**Proposed**
Basic Service Charge per Month:	$10.75	$18.00
Energy Charge per kWh:	$ 0.08076	$ 0.07618

Availability of Service: Text proposed to be added to clarify that single phase service is for secondary service only.

Residential Time-of-Day Energy Service - Rate RTOD-Energy

Current – This rate schedule is not currently available.

Proposed

Basic Service Charge per Month:	$18.00
Plus an Energy Charge per kWh:	
Off-Peak Hours	$ 0.05271
On-Peak Hours	$ 0.21483

Availability of Service: 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. 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 street or highways. 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 the rate schedule.

Determination of Pricing Periods: Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends.

Summer Period - Five Billing Periods of May through September
Weekdays: Off Peak (5pm-1pm), On Peak (1pm-5pm)
Weekends: Off Peak (All Hours), On Peak (N/A)

Winter Period - All Other Months
Weekdays: Off Peak (11am-7am), On Peak (7am-11am)
Weekends: Off Peak (All Hours), On Peak (N/A)

Minimum Bill: The Basic Service Charge shall be the minimum charge.

Residential Time-of-Day Demand Service - Rate RTOD-Demand

Current – This rate schedule is not currently available.

Proposed

Basic Service Charge per Month:	$18.00
Plus an Energy Charge per kWh:	$ 0.04008
Plus a Demand Charge per kW:	
Off-Peak Hours	$ 2.95
On-Peak Hours	$10.90

Availability of Service: 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. 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 street or highways. 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 the rate schedule.

Determination of Pricing Periods: Pricing periods are established in Eastern Standard Time year round by season for weekdays and weekends.

Summer Period - Five Billing Periods of May through September
Weekdays: Off Peak (5pm-1pm), On Peak (1pm-5pm)
Weekends: Off Peak (All Hours), On Peak (N/A)
Winter Period - All Other Months
Weekdays: Off Peak (11am-7am), On Peak (7am-11am)
Weekends: Off Peak (All Hours), On Peak (N/A)

Minimum Bill: The Basic Service Charge shall be the minimum charge.

Volunteer Fire Department Service - Rate VFD

	Current	**Proposed**
Basic Service Charge per Month:	$10.75	$18.00
Energy Charge per kWh:	$ 0.08076	$ 0.07618

General Service - Rate GS

Single Phase	**Current**	**Proposed**
Basic Service Charge per Month	$20.00	$25.00
Energy Charge per kWh	$ 0.09134	$ 0.09245
Three Phase		
Basic Service Charge per Month	$35.00	$40.00
Energy Charge per kWh	$ 0.09134	$ 0.09245

Power Service – Rate PS

Secondary Service	**Current**	**Proposed**
Basic Service Charge (per Month)	$90.00	$90.00
Energy Charge (per kWh)	$ 0.04060	$ 0.04071
Demand Charge (per kW per month of billing demand)		
Summer Rate (May through September)	$16.40	$17.33
Winter Rate (All Other Months)	$14.01	$14.94

Primary Service	**Current**	**Proposed**
Basic Service Charge (per Month)	$170.00	$200.00
Energy Charge (per kWh)	$ 0.03926	$ 0.03964
Demand Charge (per kW per month of billing demand)		
Summer Rate (May through September)	$ 13.95	$ 14.62
Winter Rate (All Other Months)	$ 11.66	$ 12.33

Time-of-Day Secondary Service Rate TODS

	Current	**Proposed**
Basic Service Charge (per Month)	$200.00	$200.00
Energy Charge (per kWh)	$ 0.03990	$ 0.04048
Maximum Load Charge (per kW per month)		
Peak Demand Period	$ 6.11	$ 6.37
Intermediate Demand Period	$ 4.51	$ 4.76

Base Demand Period	$ 4.00	$ 4.26

Industrial Time-of-Day Primary Service Rate ITODP

Current

Availability of Service: Eligibility for taking service under this rate will be calculated on 12-month average of monthly maximum loads

Basic Service Charge (per Month)	$300.00
Energy Charge (per kWh)	$ 0.03538
Maximum Load Charge (per kVA per month)	
Peak Demand Period	$ 4.63
Intermediate Demand Period	$ 3.79
Base Demand Period	$ 3.63

Summer Period - Five Billing Periods of May through September
Weekdays: Base (all hours), Interm. (10am-10pm), Peak (1pm-7pm)
Weekends: Base (all hours), Interm. (N/A), Peak (N/A)
Winter Period - All Other Months
Weekdays: Base (all hours), Interm (6am-10pm), Peak (6am-12noon)
Weekends: Base (all hours), Interm. (N/A), Peak (N/A)
Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Proposed

Rate ITODP will be combined with Commercial Time-of-Day Primary Service Rate CTODP and renamed TODP. Company will migrate customers currently served under Rate ITODP to proposed Rate TODP (see below) unless a customer is not eligible to take service under Rate TODP, in which case Company will migrate customer to the appropriate rate schedule.

Commercial Time-of-Day Primary Service Rate CTODP

Current

Availability of Service: Eligibility for taking service under this rate will be calculated on 12-month average of monthly maximum loads

Basic Service Charge (per Month)	$300.00
Energy Charge (per kWh)	$ 0.03810
Maximum Load Charge (per kVA per month)	
Peak Demand Period	$ 5.83
Intermediate Demand Period	$ 4.13
Base Demand Period	$ 3.98

Summer Period - Five Billing Periods of May through September
Weekdays: Base (all hours), Interm. (10am-10pm), Peak (1pm-7pm)
Weekends: Base (all hours), Interm. (N/A), Peak (N/A)
Winter Period - All Other Months
Weekdays: Base (all hours), Interm (6am-10pm), Peak (6am-12noon)
Weekends: Base (all hours), Interm. (N/A), Peak (N/A)
Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Proposed

Rate CTODP will be combined with Industrial Time-of-Day Primary Service Rate ITODP and renamed TODP. Company will migrate customers currently served under Rate CTODP to proposed Rate TODP (see below) unless a customer is not eligible to take service under Rate TODP, in which case Company will migrate customer to the appropriate rate schedule.

Time-of-Day Primary Service Rate TODP

Proposed (This rate is not currently available. Previously available separately as Commercial Time-of-Day Rate CTODP or Industrial Time-of-Day Rate ITODP)

Availability of Service: Available to any customer: (1) who has a 12-month average monthly minimum average demand exceeding 250 kVA; and (2) whose new or additional load receives any required approval of Company's transmission operator.

Basic Service Charge (per Month)	$300.00
Energy Charge (per kWh)	$ 0.03823
Maximum Load Charge (per kVA per month)	
Peak Demand Period	$ 5.04
Intermediate Demand Period	$ 3.69
Base Demand Period	$ 3.54

Summer Period - Five Billing Periods of May through September
Weekdays: Base (all hours), Interm. (10am-10pm), Peak (1pm-7pm)
Weekends: Base (all hours), Interm. (N/A), Peak (N/A)
Winter Period - All Other Months of October continuously through April
Weekdays: Base (all hours), Interm (6am-10pm), Peak (6am-12noon)
Weekends: Base (all hours), Interm. (N/A), Peak (N/A)

Where:

the monthly billing demand for the Peak and Intermediate Demand Periods is the greater of:

a) the maximum measured load in the current billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods, and

the monthly billing demand for the Base Demand Period is the greater of:

a) the maximum measured load in the current billing period but not less than 250 kVA, or
b) a minimum of 75% of the highest billing demand in the preceding eleven (11) monthly billing periods, or
c) a minimum of 75% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Retail Transmission Service - Rate RTS

Availability of Service:

Current: This schedule is available for transmission service. Service under this schedule will be limited to customers whose 12-month-average monthly maximum new loads do not exceed 50,000 kVA. Existing customers may increase loads to a 12-month-average monthly maximum of 75,000 kVA by up to 2,000 kVA per year or in greater increments with approval of

Company's transmission operator.

Proposed: This schedule is available for transmission service to any customer: (1) who has a 12-month average monthly minimum average demand exceeding 250 kVA; and (2) whose new or additional load receives any required approval of Company's transmission operator.

	Current	**Proposed**
Basic Service Charge (per Month)	$750.00	$1,000.00
Energy Charge (per kWh)	$ 0.03610	$ 0.03712
Maximum Load Charge (per kVA per month)		
Peak Demand Period	$ 4.55	$ 4.67
Intermediate Demand Period	$ 3.00	$ 3.12
Base Demand Period	$ 2.75	$ 2.87

Fluctuating Load Service Rate FLS

Primary Service	**Current**	**Proposed**
Basic Service Charge (per Month)	$750.00	$1,000.00
Energy Charge (per kWh)	$ 0.03610	$ 0.03709
Maximum Load Charge (per kVA per month)		
Peak Demand Period	$ 2.94	$ 3.02
Intermediate Demand Period	$ 1.89	$ 1.94
Base Demand Period	$ 1.89	$ 1.94

Transmission Service	**Current**	**Proposed**
Basic Service Charge (per Month)	$750.00	$1,000.00
Energy Charge (per kWh)	$ 0.03610	$ 0.03709
Maximum Load Charge (per kVA per month)		
Peak Demand Period	$ 2.94	$ 3.02
Intermediate Demand Period	$ 1.89	$ 1.94
Base Demand Period	$ 1.14	$ 1.17

Lighting Service - Rate LS

Current: For poles installed prior to 8/1/2010, such charge for each pole and span of secondary installed after 6/30/2004 and used in providing a light offered under LS as listed under RLS Sheet No. 36, Bill Code 958, and such charge for each pole and span of secondary installed prior to 6/30/2004 and used in providing a light offered under LS as listed under RLS Sheet No. 36, Bill Code 900.

Proposed: For wood poles installed prior to 3/1/2010, such charge will be in accordance with the rates listed on Sheet No. 36.1 of the Restricted Lighting Service Tariff.

	Rate Per Light Per Month	
OVERHEAD SERVICE	**Current**	**Proposed**
High Pressure Sodium		
452 Cobra Head, 16000 Lumen Fixture Only	$12.82	$13.20
453 Cobra Head, 28500 Lumen Fixture Only	$15.08	$15.52
454 Cobra Head, 50000 Lumen Fixture Only	$17.38	$17.89
455 Directional, 16000 Lumen Fixture Only	$13.77	$14.18
456 Directional, 50000 Lumen Fixture Only	$18.21	$18.75
457 Open Bottom, 9500 Lumen Fixture Only	$10.86	$11.18
Metal Halide		
470 Directional, 12000 Lumen Fixture Only	$12.79	$13.17
473 Directional, 32000 Lumen Fixture Only	$18.68	$19.23
476 Directional, 107800 Lumen Fixture Only	$39.60	$40.77

Rate Per Light Per Month

UNDERGROUND SERVICE	**Current**	**Proposed**
High Pressure Sodium		
412 Colonial, 4Sided, 5800 Lumen Smooth Pole	$19.79	$20.37
413 Colonial, 4Sided, 9500 Lumen Smooth Pole	$20.49	$21.09
444 Colonial, 4Sided, 16000 Lumen Smooth Pole	$20.73	$21.34
415 Acorn, 5800 Lumen Smooth Pole	$20.18	$20.78
416 Acorn, 9500 Lumen Smooth Pole	$22.56	$23.23
445 Acorn, 16,000 Lumen Smooth Pole	$22.67	$23.34
427 London, 5800 Lumen Fluted Pole	$35.20	$36.24
429 London, 9500 Lumen Fluted Pole	$36.07	$37.13
431 Victorian, 5800 Lumen Fluted Pole	$32.93	$33.90
433 Victorian, 9500 Lumen Fluted Pole	$34.99	$36.02
400 Dark Sky, 4000 Lumen	$23.89	$24.59
401 Dark Sky, 9500 Lumen	$24.90	$25.63
956 Victorian/London Bases - Westchester/Norfolk	$ 3.56	$ 3.67
423 Cobra Head, 16000 Lumen Smooth Pole	$26.35	$27.13
424 Cobra Head, 28500 Lumen Smooth Pole	$28.45	$29.29
425 Cobra Head, 50000 Lumen Smooth Pole	$34.03	$35.03
439 Contemporary, 16000 Lumen Fixture Only	$16.46	$16.95
420 Contemporary, 16000 Lumen Fixture & Pole	$29.89	$30.77
440 Contemporary, 28500 Lumen Fixture Only	$18.28	$18.82
421 Contemporary, 28500 Lumen Fixture & Pole	$32.86	$33.83
441 Contemporary, 50000 Lumen Fixture Only	$22.32	$22.98
422 Contemporary, 50000 Lumen Fixture & Pole	$38.39	$39.52
Metal Halide		
479 Contemporary, 12000 Lumen Fixture Only	$14.06	$14.47
480 Contemporary, 12000 Lumen Fixture & Pole	$23.83	$24.53
481 Contemporary, 32000 Lumen Fixture Only	$20.46	$21.06
482 Contemporary, 32000 Lumen Fixture & Pole	$30.21	$31.10
483 Contemporary, 107800 Lumen Fixture Only	$42.56	$43.82
484 Contemporary, 107800 Lumen Fixture & Pole	$52.31	$53.85

Restricted Lighting Service – Rate RLS

Availability of Service:

Current: Service under this rate schedule is restricted to those lighting fixtures in service as of August 1, 2012, except where a spot replacement maintains the continuity of multiple fixtures/poles composing a neighborhood lighting system.

Proposed: Service under this rate schedule is restricted to those lighting fixtures in service as of January 1, 2013, except where a spot replacement maintains the continuity of multiple fixtures/poles composing a neighborhood lighting system or continuity is desired for a subdivision being developed in phases.

	Rate Per Light Per Month	
OVERHEAD SERVICE	**Current**	**Proposed**
Mercury Vapor		
252 Cobra/Open Bottom 8000L Fixture Only		$ 9.59
252 Cobra/Open Bottom 8000L Fixture Only	$ 9.57	(Consolidated Above)
458 Cobra Head 8000 Lumen Fixture Only	$11.13	
203 Cobra Head 13000 Lumen Fixture Only	$10.96	$11.28
204 Cobra Head 25000 Lumen Fixture Only	$13.51	$13.91
209 Cobra Head 60000 Lumen Fixture Only	$27.69	$28.51
207 Directional 25000 Lumen Fixture Only	$15.54	$16.00
210 Directional 60000 Lumen Fixture Only	$28.89	$29.74

201 Open Bottom 4000 Lumen Fixture Only	$ 8.14	$ 8.38
Metal Halide		
471 Directional, 12000 Lumen Fixture & Wood Pole	$15.07	$15.51
474 Directional, 32000 Lumen Fixture & Wood Pole	$20.97	$21.59
475 Directional, 32000 Lumen Fixture & Metal Pole	$28.42	$29.26
477 Directional, 107800 Lumen Fixture & Wood Pole	$42.78	$44.04
Wood Pole		
958 Wood Pole Installed Before 3/1/2010	$11.31	$11.64
900 Wood Pole Installed Before 7/1/2004	$ 2.06	$ 2.12

	Rate Per Light Per Month	
UNDERGROUND SERVICE	**Current**	**Proposed**
High Pressure Sodium		
275 Cobra/Contemporary 16000L Fixture & Smooth Pole	$24.89	$25.62
266 Cobra/Contemporary 28500L Fixture & Smooth Pole	$27.34	$28.15
267 Cobra/Contemporary 50000L Fixture & Smooth Pole	$31.40	$32.33
276 Coach/Acorn 5800 Lumen Fixture & Smooth Pole	$14.17	$14.59
274 Coach/Acorn 9500 Lumen Fixture & Smooth Pole	$17.19	$17.70
277 Coach/Acorn 16000 Lumen Fixture & Smooth Pole	$22.15	$22.80
279 Contemporary 120000 Lumen Fixture Only	$41.43	$42.65
278 Contemporary 120000 Lumen Fixture & Smooth Pole	$72.55	$74.69
417 Acorn 9500 Lumen Bronze Decorative Pole	$23.68	$24.38
419 Acorn 16000 Lumen Bronze Decorative Pole	$24.77	$25.50
280 Victorian 5800 Lumen Fixture Only	$19.38	$19.95
281 Victorian 9500 Lumen Fixture Only	$20.35	$20.95
282 London 5800 Lumen Fixture Only	$19.53	$20.11
283 London 9500 Lumen Fixture Only	$20.82	$21.43
426 London, 5800 Lumen Fixture & Pole	$33.22	$34.20
428 London, 9500 Lumen Fixture & Pole	$34.09	$35.10
430 Victorian, 5800 Lumen Fixture & Pole	$32.26	$33.21
432 Victorian, 9500 Lumen Fixture Pole	$34.33	$35.34
950 Victorian/London Bases, Old Town	$ 3.47	$ 3.57
951 Victorian/London Bases, Chesapeake	$ 3.73	$ 3.84
901 Smooth 10’ Pole	$10.81	$11.13
902 Fluted 10’ Pole	$12.90	$13.28
Mercury Vapor		
318 Cobra Head, 8000 Lumen Fixture & Pole	$17.42	$17.93
314 Cobra Head, 13000 Lumen Fixture & Pole	$19.20	$19.77
315 Cobra Head, 25000 Lumen Fixture & Pole	$22.95	$23.63
347 Cobra Head, 25000 Lumen St. of Ky. Pole	$22.94	$23.62
206 Coach, 4000 Lumen Fixture & Pole	$12.45	$12.82
208 Coach, 8000 Lumen Fixture & Pole	$14.24	$14.66
Incandescent		
349 Continental Jr, 1500 Lumen Fixture & Pole	$ 9.02	$ 9.29
348 Continental Jr, 6000 Lumen Fixture & Pole	$13.12	$13.51

Lighting Energy Service - Rate LE

	Current	**Proposed**
Energy Charge per kWh:	$0.06461	$0.06661

Traffic Energy Service Rate TE

	Current	Proposed
Basic Service Charge per Month:	$3.25	$4.00
Energy Charge per kWh:	$0.07658	$0.07659

Cable Television Attachment Charges – Rate CTAC

Attachment Charge per year	Current	Proposed
for each attachment to pole:	$9.11	$9.11

Curtailable Service Rider 10 – Rider CSR10

Primary	**Current**	**Proposed**
Monthly Demand Credit Per kVA:	($ 5.50)	($ 5.50)
Non-Compliance Charge:	$16.00	$16.00
Transmission	**Current**	**Proposed**
Monthly Demand Credit Per kVA:	($ 5.40)	($ 5.40)
Non-Compliance Charge:	$16.00	$16.00

Company further proposes text changes to: (1) eliminate buy-through hours and Automatic Buy Through Pricing; (2) eliminate all restrictions on Company's ability to request physical-curtailment hours, though Company does not propose to change the number of physical-curtailment hours; (3) replace all references of "kW" and "MW" with "kVA" and "MVA," respectively; and (4) to require each customer taking service under CSR10 to demonstrate or certify to Company's satisfaction at the commencement of service and annually thereafter the customer's capability to reduce its demand pursuant to the amount designated in the contract in the event of a request for curtailment

Curtailable Service Rider 30 – Rider CSR30

Primary	**Current**	**Proposed**
Monthly Demand Credit Per kVA:	($ 4.40)	($ 4.40)
Non-Compliance Charge:	$16.00	$16.00
Transmission	**Current**	**Proposed**
Monthly Demand Credit Per kVA:	($ 4.30)	($ 4.30)
Non-Compliance Charge:	$16.00	$16.00

Company further proposes text changes to: (1) eliminate buy-through hours and Automatic Buy Through Pricing; (2) eliminate all restrictions on Company's ability to request physical-curtailment hours, though Company does not propose to change the number of physical-curtailment hours; (3) replace all references of "kW" and "MW" with "kVA" and "MVA," respectively; and (4) to require each customer taking service under CSR30 to demonstrate or certify to Company's satisfaction at the commencement of service and annually thereafter the customer's capability to reduce its demand pursuant to the amount designated in the contract in the event of a request for curtailment.

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	1.32%	1.32%
(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	0.54%	0.54%

Net Metering Service – Rate NMS

Company proposes text changes to the definition of "Billing Period Credit" to clarify that such a credit is a kWh-denominated electricity credit only, not a monetary credit. Company further proposes text changes to the Metering and Billing section to clarify how the Company accounts for billing period credits for customers taking service under time-of-day rates.

Standard Rider for Redundant Capacity Charge – Rider RC

	Current **(Per kW/kVA)**	**Proposed** **(Per kW/kVA)**
Capacity Reservation Charge per Month:		
Secondary Distribution	$1.17	$1.43
Primary Distribution	$0.83	$1.26

Standard Rider for Supplemental or Standby Service – Rider SS

	Current **(Per kW/kVA)**	**Proposed** **(Per kW/kVA)**
Contract Demand per month:		
Secondary	$12.86	$13.57
Primary	$12.23	$12.30
Transmission	$11.04	$10.83

Also, Company proposes text changes to the Minimum Charge provision to clarify that for a Rider SS customer, Company will bill the customer monthly for all of the charges under the customer's applicable rate schedule, including, but not limited to, the applicable basic service charge, energy charges, and adjustment clauses. In addition to those charges, Company will bill the customer monthly a demand charge that is the greater of: (1) the customer's total demand charge calculated under the applicable rate schedule; or (2) the demand charge calculated using the applicable demand rate shown above applied to the Contract Demand.

Temporary and/or Seasonal Electric Service Rider TS

Availability of Service:

Current: This rider is available at the option of the Customer where Customer's business does not require permanent installation of Company's facilities and is of such nature to require:

1. only seasonal service or temporary service, including service provided for construction of residences or commercial buildings, and where in the judgment of Company the local and system electrical facility capacities are adequate to serve the load without impairment of service to other customers; or
2. where Customer has need for temporary use of Company facilities and Company has facilities it is willing to provide.

This service is available for not less than one (1) month (approximately 30 days), but when service is used longer than one (1) month, any fraction of a month's use will be prorated for billing purposes.

Proposed: This rider is available at the option of the 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. where 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.

Standard Rate for Low Emission Vehicle Service – Rate LEV

Current

Basic Service Charge per Month:	$10.75
Energy Charge per kWh:	
Off-Peak Hours	$0.05820
Intermediate Hours	$0.07899
Peak Hours	$0.14451

Proposed – This rate schedule is proposed to be eliminated. The Company will make all reasonable efforts to contact Rate LEV customers to advise them of their new rate options after the Commission approves the new rates but before they take effect (at which time Rate LEV will terminate). Because Rate RTOD-Energy is the new rate most similar to Rate LEV, the Company will automatically transfer to Rate RTOD-Energy all Rate LEV customers who have not responded to the Company's outreach efforts by the effective date of the new rates; however, the Company will continue to make reasonable efforts to obtain those customers' input even after the rate change.

Economic Development Rider – Rider EDR

Company proposes changes to Rider EDR's Terms and Conditions to: (1) clarify the minimum demand required for the rider to be available to customer; (2) increase the range of certifications that can make a customer eligible for Rider EDR to include 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; and (3) clarify that no credit under EDR will be calculated or applied to a customer's billing in any billing month in which the customer's metered load is less than the load required to be eligible for either Brownfield Development or Economic Development.

Meter Test Charge

Current Rate:	$75.00
Proposed Rate:	$75.00

Disconnect/Reconnect 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:

$15.00 per month per installed set of pulse-generating equipment

Customer Deposits

Current Rate

For Customers Served Under Residential Service Rate RS:	$135.00
(For Combination Electric and Gas Residential Customers the total deposit would be $230.00)	
For Customers Served Under General Service Rate GS	$220.00

For all other Customers not classified herein, the deposit will be no more than 2/12 of Customer's actual or estimated annual bill where bills are rendered monthly.

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 Combination Electric and Gas Residential Customers the total deposit would be $260.00)
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 – Customer Responsibilities

Adding the following provision that could result in a charge to certain customers:

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.

Terms and Conditions – Budget Payment Plan

Current:

Company's Budget Payment Plan is available to any residential customer or general service customer. Under this plan, a customer may elect to pay, each billing period, a budgeted amount in lieu of billings for actual usage. A customer may enroll in the plan at any time.

Proposed:

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 the plan at any time.

LG&E CURRENT AND PROPOSED GAS RATES

Residential Gas Service - Rate RGS

	Current	Proposed
Basic Service Charge per delivery point per month:	$13.50	$19.00
Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.26419	$ 0.21325
Gas Supply Cost Component	0.56128	0.56128
Total Charge Per 100 Cubic Feet	$ 0.82547	$ 0.77453

Volunteer Fire Department Service – Rate VFD

	Current	Proposed
Basic Service Charge per delivery point per month:	$13.50	$19.00
Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.26419	$ 0.21325
Gas Supply Cost Component	0.56128	0.56128
Total Charge Per 100 Cubic Feet	$ 0.82547	$ 0.77453

Firm Commercial Gas Service - Rate CGS

	Current	Proposed
Basic Service Charge per delivery point per month if all of the customer's meters have a capacity < 5000 cf/hr:	$ 35.00	$ 40.00
Basic Service Charge per delivery point per month if all of the customer's meters have a capacity > 5000 cf/hr:	$175.00	$180.00
Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.20999	$ 0.23445

	Current	Proposed
Gas Supply Cost Component	0.56128	0.56128
Total Charge Per 100 Cubic Feet	$ 0.77127	$ 0.79573

Firm Industrial Gas Service - Rate IGS

	Current	Proposed
Basic Service Charge per delivery point per month if all of the customer's meters have a capacity < 5000 cf/hr:	$ 35.00	$ 40.00
Basic Service Charge per delivery point per month if all of the customer's meters have a capacity > 5000 cf/hr:	$175.00	$180.00
Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.21452	$ 0.24305
Gas Supply Cost Component	0.56128	0.56128
Total Charge Per 100 Cubic Feet	$ 0.77580	$ 0.80433

As-Available Gas Service – Rate AAGS

	Current	Proposed
Basic Service Charge per delivery point per month:	$275.00	$400.00
Charge Per Mcf:		
Distribution Cost Component	$ 0.6086	$ 0.8285
Gas Supply Cost Component	5.6128	5.6128
Total Charge Per 100 Cubic Feet	$ 6.2214	$ 6.4413

Current:

Customer shall be charged a per Mcf penalty charge equal to $15.00 plus the mid-point price posted in "Platts Gas Daily" for Dominion--South Point on the day to which such interruption of service is applicable, plus any other charges under this rate schedule for such unauthorized usage by Customer that occurs following the conclusion of the eighteen- (18-) hour notice of interruption by Company to Customer.

If Customer is delivering quantities of gas to Company pursuant to Rider TS during such period of interruption, the charge described in the immediately preceding paragraph shall be applicable only to those quantities used by customer in excess of those being delivered by Customer to Company.

Proposed:

Customer shall be charged a per Mcf penalty charge applicable to any unauthorized takes of gas during the period of interruption (excluding Pilot Light Requirements where applicable) equal to $15.00 plus the higher of the following: either (a) the highest daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the period of interruption that falls into each monthly billing cycle, or (b) the highest daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during the period of interruption that falls into each monthly billing cycle. Such penalty for failure to interrupt shall be in addition to any other charges under this rate schedule for such unauthorized usage by Customer that occurs following the conclusion of the eighteen- (18-) hour notice of interruption by Company to Customer.

Current: The Customer shall be responsible for the cost of the remote metering equipment and the cost of its installation.

Proposed: The Customer shall reimburse Company for the cost of the remote metering equipment, for any modifications to Company facilities, and for the replacement of any existing meters required in order to facilitate the functioning of the remote metering.

Firm Transportation Service (Transportation Only) Rate FT

	Current	Proposed

Administration Charge per delivery point per month:	$400.00	$550.00
Distribution Charge Per Mcf	$ 0.4300	$ 0.4431
Utilization Charges for		
Daily Imbalances:		
Daily Demand Charge	$ 0.1576	$ 0.1576
Daily Storage Charge	0.1833	0.1833
Utilization Charge Per Mcf	$ 0.3409	$ 0.3409

Plus: Any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas.

Current:

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from Customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lowest daily mid-point price posted in "Platts Gas Daily" for Dominion South Point during the month in which the imbalance occurred.

Proposed:

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from Customer at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either (a) the lowest daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred.

Current:

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall be billed for the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the highest daily mid-point price posted in "Platts Gas Daily" for Dominion South Point during the month in which the imbalance occurred.

Proposed:

If the monthly imbalance is positive (an under-delivery into Company's system), Customer shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred.

Current:

These charges are in addition to any other charges set forth herein. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed ±5% of the delivered volume.

Proposed:

These charges are in addition to any other charges set forth herein. The Utilization Charge for Daily Imbalances will not be applied to daily imbalances which do not exceed ±5% of the delivered volume unless an OFO has been issued. If an OFO has been issued, the Utilization Charge for Daily Imbalances shall apply to daily imbalances which exceed 0% for customers in violation of the OFO directive, either “condition (a)” or “condition (b)” as applicable and further described below under “Operational Flow Orders”. Customers not in violation of the OFO directive, either “condition (a)” or “condition (b)” as applicable, will continue to be assessed the Utilization Charge for Daily Imbalances on volumes which exceed the 5% daily tolerance.

Current:

All volumes taken by Customer less than volumes delivered by Pipeline Transporter to Company for Customer in violation of the above “condition (b)” OFO shall constitute an unauthorized delivery by Customer to Company. Customer shall be subject to the OFO Charge on the day for which the OFO was violated, plus the applicable UCDI charges and any other charges under this rate schedule for such unauthorized receipts or deliveries that occur.

Proposed:

All volumes taken by Customer less than volumes delivered by Pipeline Transporter to Company for Customer in violation of the above “condition (b)” OFO shall constitute an unauthorized delivery by Customer to Company. Unauthorized receipts or deliveries during the effectiveness of an OFO shall be subject to an OFO Charge per Mcf for each Mcf of unauthorized receipts or deliveries, as applicable. Customer shall be subject to the OFO Charge on the day for which the OFO was violated, plus the applicable UCDI charges and any other charges under this rate schedule for such unauthorized receipts or deliveries that occur.

Current:

The OFO Charge shall be equal to $15.00 plus the mid-point price posted in "Platts Gas Daily” for Dominion South Point per Mcf on the day for which the OFO was violated, plus any other charges under this rate schedule.

Proposed:

The OFO Charge per Mcf shall be equal to $15.00 plus the higher of the following: either (a) the daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS for the day on which the OFO was violated, or (b) the daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS for the day on which the OFO was violated. Such OFO Charge shall be in addition to any other charges under this rate schedule.

Current:

The Customer shall be responsible for the cost of this remote metering equipment and the cost of its installation.

Proposed:

The Customer shall reimburse Company for the cost of this remote metering equipment and the cost of its installation, including any modifications to Company facilities and the replacement of any existing meters required in order to facilitate the functioning of the remote metering.

Distribution Generation Gas Service - Rate DGGS

	Current	**Proposed**
Basic Service Charge per delivery point per month if all of the customer’s meters have a capacity < 5000 cf/hr:	$ 35.00	$ 40.00
Basic Service Charge per delivery point per month if all of the customer’s meters have a capacity > 5000 cf/hr:	$175.00	$180.00
Demand Charge Per 100 Cubic Feet	$ 1.1402	$ 1.1685
Charge Per 100 Cubic Feet:		
Distribution Cost Component	$ 0.03095	$ 0.03454
Gas Supply Cost Component	0.56128	0.56128

Total Charge Per 100 Cubic Feet	$ 0.59223	$ 0.59582

The minimum Monthly Billing Demand is four hundred and eighty (480) Ccf.

Gas Transportation Service/Standby - Rider TS

Current Rate

Administration Charge: $400.00 per Delivery Point per month.

	CGS	IGS	AAGS
Distribution Charge Per Mcf	$2.0999	$2.1452	$0.6086
Pipeline Supplier's Demand Component	0.7792	0.7792	0.7792
Total	$2.8791	$2.9244	$1.3878

Plus: Any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas.

Proposed Rate

This rate is proposed to be eliminated.

RIDER TS-2
Gas Transportation Service/Firm Balancing Service Rider

Current Rate

Administrative Charge: $400.00 per Delivery Point per month.
Monthly Telemetry Charge Per Delivery Point Per Month: $300.00

	CGS	IGS	AAGS
Distribution Charge Per Mcf	$2.0999	$2.1452	$0.6086
Pipeline Supplier's Demand Component	0.7792	0.7792	0.7792
Total	$2.8791	$2.9244	$1.3878

Plus: Any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas.

Proposed Rate

Administrative Charge: $550.00 per Delivery Point per month.
Monthly Telemetry Charge Per Delivery Point Per Month: $300.00

	CGS	IGS	AAGS
Distribution Charge Per Mcf	$2.3445	$2.4305	$0.8285
Pipeline Supplier's Demand Component	0.7792	0.7792	0.7792
Total	$3.1237	$3.2097	$1.6077

Plus: Any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas.

Current:

At the time that the Customer executes a contract for service hereunder, Customer shall elect to either (1) pay for the cost of this remote metering equipment and the cost of its installation (including any required meter replacement) in an up-front lump sum payment, or (2) pay the Optional Monthly Telemetry Charge specified herein.

Proposed:

At the time that the Customer executes a contract for service hereunder, Customer shall elect to either (1) pay for the cost of this remote metering equipment and the cost of its installation in an up-front lump sum payment, or (2) pay the Optional Monthly Telemetry Charge specified herein. Under either option, Customer shall reimburse Company for the cost of any modifications to Company facilities and the replacement of any existing meters required in order to facilitate the functioning of the remote metering.

Gas Meter Pulse Service Rider GMPS

Monthly Charge:	**Current**	**Proposed**
For Customers Served Under Rate Schedule FT and Rider TS-2:	$ 7.17	$ 7.17
For Customers Not Served Under Rate Schedule FT and Rider TS-2:	$24.34	$24.34

RIDER PS-TS-2

Pooling Service Rider to Rider TS-2

Current Rate

In addition to any charges billed directly to TS-2 Pool Manager or Customer as a result of the application of Rider TS-2 or this rider, the following PS-TS-2 Pool Administrative Charge shall apply per Customer per month: $75.00

In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by the Pipeline Transporter, then the Company proposes to require Customer to pay such penalties, fees or charges as determined by Company and in accordance with the payment provisions of the applicable rate schedule in addition to any and all other charges due thereunder.

Action Alert Charge

Company shall have the right to issue an Action Alert ("AA") which will require actions by the TS-2 Pool Manager to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. Upon issuance of an AA, Company will direct TS-2 Pool Manager to deliver to Company from 0% to 100% of the total MDQ of those Customers in the TS-2 Pool (the PMDQ as defined hereafter). Any volume delivered by TS-2 Pool Manager that differs (either more or less) from the volume specified in the AA shall be subject to an Action Alert Charge. The Action Alert Charge shall be equal to $5.00 plus the mid-point price posted in *Platts Gas Daily* for Dominion South Point per Mcf on the day for which the AA was violated, plus any other charges under this rider.

Proposed Rate

In addition to any charges billed directly to TS-2 Pool Manager or Customer as a result of the application of Rider TS-2 or this rider, the following PS-TS-2 Pool Administrative Charge shall apply per Customer per month: $75.00

In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by the Pipeline Transporter, then the Company proposes to require Customer to pay such penalties, fees or charges as determined by Company and in accordance with the payment provisions of the applicable rate schedule in addition to any and all other charges due thereunder.

Action Alert Charge

Company shall have the right to issue an Action Alert ("AA") which will require actions by the TS-2 Pool Manager to alleviate conditions that, in the sole judgment of Company, jeopardize the operational integrity of Company's system. Upon issuance of an AA, Company will direct TS-2 Pool Manager to deliver to Company from 0% to 100% of the total MDQ of those Customers in the TS-2 Pool (the PMDQ as defined hereafter). Any volume delivered by TS-2 Pool Manager that differs (either more or less) from the volume specified in the AA shall be subject to an Action Alert Charge. The Action Alert Charge shall be equal to $5.00 plus the higher of the following: either (a) the daily mid-point price posted in "*Platts Gas Daily*" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any applicable surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the AA was violated, or (b) the daily mid-point price posted in "*Platts Gas Daily*" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any applicable surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS for the day on which the AA was violated. Such Action Alert Charge shall be in addition to any other charges under this rider.

Current:

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from TS-2 Pool Manager at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lowest daily mid-point price posted in "Platts Gas Daily" for Dominion South Point during the month in which the imbalance occurred.

Proposed:

If the monthly imbalance is negative (an over-delivery into Company's system), Company shall purchase the monthly imbalance from TS-2 Pool Manager at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the lower of the following: either (a) the lowest daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred, or (b) the lowest daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred.

Current:

If the monthly imbalance is positive (an under-delivery into Company's system), TS-2 Pool Manager shall be billed for the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the highest daily mid-point price posted in "Platts Gas Daily" for Dominion South Point during the month in which the imbalance occurred.

Proposed:

If the monthly imbalance is positive (an under-delivery into Company's system), TS-2 Pool Manager shall purchase the monthly imbalance from Company at a price per Mcf which is determined by multiplying the appropriate percentage specified below times the higher of the following: either (a) the highest daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred, or (b) the highest daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during the month in which the imbalance occurred.

Pooling Service Rider to Rate FT - Rider PS-FT

In addition to any charges billed directly to FT Pool Manager or Customer as a result of the application of Rate FT or this rider, the following charge shall apply per customer in FT Pool per month:

	Current	Proposed
PS-FT Pool Administration Charge:	$75	$75

In the event that Customer is determined to be the cause of any billing disadvantages or other penalties imposed on Company by the Pipeline Transporter, then the Company proposes to require Customer to pay such penalties, fees or charges as determined by Company and in accordance with the payment provisions of the applicable rate schedule in addition to any and all other charges due thereunder.

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%	1.24%
(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	0.47%	0.47%

Natural Gas Vehicle Service - Rider NGV

This is a new rider available to municipal, utility, corporate and other fleet operators and public fueling stations meeting the qualifications of, and served under, either Rate IGS or Rate FT for the sole purpose of providing compressed natural gas for use as a fuel in vehicular internal combustion engines. A customer served under Rate IGS that meets the qualifications for service under Rider TS-2 may also transport gas pursuant to Rider TS-2.

The rates, provisions, and special terms and conditions of Rate IGS, Rider TS-2, or Rate FT as applicable to the customer shall apply under this rider.

Service under this Rider shall be performed under a written contract between the customer and Company containing such provisions regarding delivery pressure, indemnification, and other matters as the Company deems necessary or desirable with respect to a particular customer.

The customer shall be responsible for and shall reimburse the Company for all taxes (including, but not limited to, any motor vehicle taxes) payable by the Company to any governmental body on sales of gas and/or for services rendered under this Rider.

The “Resale of Gas” provision set forth in the “Terms and Conditions” of Company’s Tariff shall not apply to service provided under this rider.

Gas Line Tracker – Adjustment Clause GLT

Company proposes to add “Property Taxes” to the list of items included in the GLT Revenue Requirement. This proposed text change is consistent with the filing LG&E made with the Commission on October 31, 2014, which proposed revised GLT tariff sheets and rates to be effective January 1, 2015. Therefore, the GLT text change reflects a change requested in another proceeding, and does not reflect a new request in this proceeding.

Meter Test Charge

Current Rate	$90.00
Proposed Rate	$90.00

Disconnect/Reconnect Service Charge

Current Rate	$28.00
Proposed Rate	$28.00

Inspection Charge
Additional Trip Charge When More Than Two are Necessary
Applicable to Rate FT, Rider TS-2, and Rider GMPS

Current Rate	$150.00
Proposed Rate	$150.00

Customer Deposits

Current Rate

For Customers Served Under
Residential Gas Service Rate RGS $ 95.00
(For Combination Gas and Electric Residential Customers,
the total deposit would be $230.00)

For Non-Residential Gas Customers, the deposit will be no more than 2/12 of Customer’s actual or estimated annual bill where bills are rendered monthly.

Proposed Rate

For Customers Served Under
Residential Gas Service Rate RGS $100.00
(For Combination Gas and Electric Residential Customers,
the total deposit would be $260.00)

For Non-Residential Gas Customers, the deposit will be no more than 2/12 of Customer’s actual or estimated annual bill where bills are rendered monthly.

Terms and Conditions – Curtailment Rules

Current:

Any customer subject to Pro-Rata curtailment in accordance with Section 3 above, who at the end of a month has taken gas in excess of its Authorized Monthly Volumes (excluding Pilot Light Requirements where applicable) for such month, may, in the sole discretion of Company, be subject to a penalty charge applicable to such excess takes of gas at the rate of $15.00 per Mcf plus the highest daily mid-point price posted in “Platts Gas Daily” for Dominion-South Point during each month of the period of curtailment, such penalty to be in addition to the established rate for service.

Any customer subject to Emergency Curtailment in accordance with Section 4 above, who uses quantities of gas in excess of authorized quantities (excluding Pilot Light Requirements where applicable) during a period of such Emergency Curtailment, may, in the sole discretion of Company, be subject to a penalty charge applicable to such unauthorized takes of gas at the rate of $15.00 per Mcf plus the highest daily mid-point price posted in “Platts Gas Daily” for Dominion-South Point during each month of the period of curtailment, such penalty to be in addition to the established rate for service.

Proposed:

Any customer subject to Pro-Rata curtailment in accordance with Section 3 above, who at the end of a month has taken gas in excess of its Authorized Monthly Volumes (excluding Pilot Light Requirements where applicable) for such month, may, in the sole discretion of Company, be subject to a penalty charge applicable to such excess takes of gas at the rate of $15.00 per Mcf plus the higher of the following: either (a) the highest daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during each month of the period of curtailment, or (b) the highest daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS during each month of the period of curtailment. Such penalty shall be in addition to the established rate for service.

Any customer subject to Emergency Curtailment in accordance with Section 4 above, who uses quantities of gas in excess of authorized quantities (excluding Pilot Light Requirements where applicable) during a period of such Emergency Curtailment, may, in the sole discretion of Company, be subject to a penalty charge applicable to such unauthorized takes of gas at the rate of $15.00 per Mcf plus the higher of the following: either (a) the highest daily mid-point price posted in "Platts Gas Daily" for Texas Gas Zone 1 adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC’s Rate NNS plus the Commodity

Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment, or (b) the highest daily mid-point price posted in "Platts Gas Daily" for Lebanon-Hub adjusted for Fuel Retention applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS plus the Commodity Charge and any surcharges applicable to deliveries to Zone 4 under Texas Gas Transmission, LLC's Rate NNS during each month of the period of curtailment. Such penalty shall be in addition to the established rate for service.

Louisville Gas and Electric Company also proposes to change the text of the following electric tariffs: Residential Service Rate RS, General Service Rate GS, Power Service Rate PS, Industrial Time-of-Day Primary Service Rate ITODP, Commercial Time-of-Day Primary Service Rate CTODP, Retail Transmission Service Rate RTS, Lighting Service Rate LS, Restricted Lighting Service Rate RLS, Special Charges, Curtailable Service Rider CSR10, Curtailable Service Rider CSR30, Net Metering Service Rate NMS, Supplemental or Standby Service Rider SS, Temporary and/or Seasonal Service Rider TS, Economic Development Rider EDR, Low Emission Vehicle Service Rate LEV, Demand Side Management Cost Recovery Mechanism DSM, Environmental Cost Recovery Surcharge ECR, and the Terms and Conditions.

Changes to the Terms and Conditions include the addition of a section on Company as a Federal Contractor, meter placement, proposed clarifications on terms and conditions specific to residential electric service, and expanded options for the Company to provide written notice for discontinuance of service due to nonpayment or non-compliance.

Louisville Gas and Electric Company also proposes to change the text of the following gas tariffs: Residential Gas Service Rate RGS, Firm Industrial Gas Service Rate IGS, As-Available Gas Service Rate AAGS, Firm Transportation Service Rate FT, Special Charges, Gas Transportation Service/Standby Rider TS-2, Pooling Service Rider PS-TS-2, Pooling Service Rate PS-FT, Gas Line Tracker GLT, Demand Side Management Cost Recovery Mechanism DSM, and the Terms and Conditions.

Changes in the Terms and Conditions include the addition of a section on Company as a Federal Contractor, the addition of text regarding delivery pressure, revised criteria for penalty charges for compliance during curtailment, and expanded options for the Company to provide written notice for discontinuance of service due to nonpayment or non-compliance.

Complete copies of the proposed tariffs containing the text changes and proposed rates may be obtained by contacting Edwin R. Staton, Louisville Gas and Electric Company at P. O. Box 32010, Louisville, Kentucky, 502-627-4314, or by visiting Louisville Gas and Electric Company's website at www.lge-ku.com.

The foregoing rates reflect a proposed annual increase in electric revenues of approximately 2.7% and gas revenues of approximately 4.2% to Louisville Gas and Electric Company.

The estimated amount of the annual change and the average monthly bill to which the proposed electric rates will apply for each electric customer class is as follows:

Electric Rate Class	**Average Monthly Usage (kWh)**	**Annual $ Increase**	**Annual % Increase**	**Monthly Bill $ Increase**	**Monthly Bill% Increase**
Residential	984	11,908,857	2.73	2.75	2.73
General Service	2,588	4,213,025	2.72	7.87	2.72
Power Service	61,846	5,269,319	2.72	153.08	2.72

TODS (Secondary)	271,647	2,347,732	2.72	612.98	2.72
CTODP to TODP (Primary)	786,184	(1,338,789)	(4.47)	(2,824.44)	(4.47)
ITODP to TODP (Primary)	1,983,900	5,526,150	4.48	6,563.12	4.48
Retail Transmission	6,089,174	1,520,807	2.73	10,561.16	2.73
Fluctuating Load	No customers are currently served under this rate schedule.				
Outdoor Lights	120	517,895	2.73	0.50	2.73
Lighting Energy	1,839	6,886	2.73	3.68	2.73
Traffic Energy	286	8,176	2.72	0.75	2.72
CTAC	N/A	0	0	0	0
LEV to RTOD-Energy	1,364	3,012	9.66	12.40	9.66

The estimated amount of the annual change and the average monthly bill to which the proposed gas rates will apply for each gas customer class is as follows:

Gas Rate Class	**Average Monthly Usage (Mcf)**	**Annual $ Increase**	**Annual % Increase**	**Monthly Bill $ Increase**	**Monthly Bill% Increase**
Residential	5.7	9,264,250	4.20	2.62	4.20
Commercial	36.7	3,973,949	4.20	13.97	4.20
Industrial	442.4	399,692	4.21	132.40	4.21
As-Available	5,803.0	99,892	4.20	1,453.46	4.20
Firm Transportation	12,188.0	293,560	4.20	309.66	4.20
Distributed Generation	No customers are currently served under this rate schedule.				

The rates contained in this notice are the rates proposed by Louisville Gas and Electric Company; however, the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice.

Notice is further given that any corporation, association, body politic or person with a substantial interest in the matter may by written request, within thirty (30) days after publication of the notice of the proposed rate changes, request to intervene. The request shall be submitted to the Public Service Commission, P. O. Box 615, Frankfort, Kentucky 40602, and shall set forth the grounds for the request, including the status and interest of the party. Intervention may be granted beyond the thirty (30) day period for good cause shown; however, if the Commission does not receive a written request for intervention within thirty (30) days of initial publication, the Commission may take final action on the application. Any person who has been granted intervention may obtain copies of the application and any other filings made by the utility by contacting Edwin R. Staton, Vice President – State Regulation and Rates, Louisville Gas and Electric Company, 220 West Main Street, Louisville, Kentucky, 502-627-4314.

A copy of the application and testimony shall be available for public inspection at the office of Louisville Gas and Electric Company, 820 West Broadway, Louisville, Kentucky.

A copy of the application and testimony shall also be available for public inspection at the offices of the Kentucky Public Service Commission 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 through its Web site or by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602.

A copy of this Notice and the proposed electric and gas tariffs, once filed, shall also be available for public inspection on Louisville Gas and Electric Company's website at www.lge-ku.com, or through the Public Service Commission’s website at http://psc.ky.gov.

Louisville Gas and Electric Company
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40232
502-627-4314

Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40601
502-564-3940

Exhibit B

Listing of Newspapers Publishing Notice

List of Newspapers in LG&E Territory

Bardstown Kentucky Standard
Bedford Trimble Banner
Brandenburg Meade County Messenger
Cave City Barren Progress
Edmonton Herald News
Elizabethtown Hardin County Independent
Elizabethtown News Enterprise
Glasgow Daily Times
Greensburg Record Herald
Hodgenville Larue County Herald
Lagrange Oldham Era
Lebanon Enterprise
Louisville Courier Journal
Munfordville Hart News Herald
New Castle Henry County Local
Shelbyville Sentinel News
Shepherdsville Pioneer News
Springfield Sun
Taylorsville Spencer Magnet

Exhibit C

Customer Bill Insert
General Statement

NOTICE TO CUSTOMERS OF
LOUISVILLE GAS AND ELECTRIC COMPANY

PLEASE TAKE NOTICE that, in a November 26, 2014 Application, Louisville Gas and Electric Company ("LG&E") is seeking approval by the Kentucky Public Service Commission ("Commission") of an adjustment of its electric and gas rates and charges to become effective on and after January 1, 2015.

The proposed rates reflect a proposed annual increase in electric revenues of approximately 2.7% and gas revenues of approximately 4.2% to LG&E.

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	Mthly Bill $ Increase	Mthly Bill % Increase
Residential	984	11,908,857	2.73	2.75	2.73
General Service	2,588	4,213,025	2.72	7.87	2.72
Power Service	61,846	5,269,319	2.72	153.08	2.72
TODS (Secondary)	271,647	2,347,732	2.72	612.98	2.72
CTOD to TODP (Primary)	786,184	(1,338,789)	(4.47)	(2,824.44)	(4.47)
ITOD to TODP (Primary)	1,983,900	5,526,150	4.48	6.563.12	4.48
Retail Transmission	6,089,174	1,520,807	2.73	10,561.16	2.73
Fluctuating Load	No customers are currently served under this rate schedule.				
Outdoor Lights	120	517,895	2.73	0.50	2.73
Lighting Energy	1,839	6,886	2.73	3.68	2.73
Traffic Energy	286	8,176	2.72	0.75	2.72
CTAC	N/A	0	0	0	0
LEV to RTOD-Energy	1,364	3,012	9.66	12.40	9.66

The estimated amount of the annual change and the average monthly bill to which the proposed gas rates will apply for each gas customer class is as follows:

Gas Rate Class	Average Usage (Mcf)	Annual $ Increase	Annual % Increase	Mthly Bill $ Increase	Mthly Bill % Increase
Residential	5.7	9,264,250	4.20	2.62	4.20
Commercial	36.7	3,973,949	4.20	13.97	4.20
Industrial	442.4	399,692	4.21	132.40	4.21
As-Available	5,803.0	99,892	4.20	1,453.46	4.20
Firm Transportation	12,188.0	293,560	4.20	309.66	4.20
Distributed Generation	No customers are currently served under this rate schedule.				

LG&E is also proposing to increase its required Customer Deposits from the current amount of $135.00 for residential electric customers to $160.00, and from the current amount of $95.00 for residential gas customers to $100.00. ("Residential electric customers" are all customers taking service under Residential Rate RS, proposed Residential Time-of-Day Energy Service Rate RTOD-Energy, and proposed Residential Time-of-Day Demand Service Rate RTOD-Demand.) The Customer Deposit for combined gas and electric residential service, if required, would increase from the current $230.00 to $260.00. LG&E is further proposing to increase the Customer Deposit for electric customers served under General Service Rate GS from $220.00 to $240.00. All other non-residential gas and electric customers will continue to pay a deposit not to exceed 2/12 of the customer's actual or estimated annual bill.

LG&E is also proposing changes in the text of some of its rate schedules and other tariff provisions, including its terms and conditions for electric or gas service. Complete copies of the proposed tariffs containing the proposed text changes and rates may be obtained by contacting Edwin R. Staton, Louisville Gas and Electric Company at 220 West Main Street, Louisville, Kentucky, 40202, 502-627-4314, or by visiting Louisville Gas and Electric Company's website at www.lge-ku.com.

LG&E's application contains the rates proposed by Louisville Gas and Electric Company; however, the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice.

Notice is further given that any corporation, association, body politic or person with a substantial interest in the matter may by written request, within thirty (30) days after publication of the notice of the proposed rate changes, request to intervene. The motion shall be submitted to the Public Service Commission, 211 Sower Boulevard, P. O. Box 615, Frankfort, Kentucky 40602, and shall set forth the grounds for the request, including the status and interest of the party. Intervention may be granted beyond the thirty (30) day period for good cause shown; however, if the Commission does not receive a written request for intervention within thirty (30) days of initial publication, the Commission may take final action on the application. Any person who has been granted intervention may obtain copies of the application and any other filings made by the utility by contacting Edwin R. Staton, Vice President – State Regulation and Rates, Louisville Gas and Electric Company, 220 West Main Street, Louisville, Kentucky, 502-627-4314.

A copy of the application and testimony shall be available for public inspection at the office of Louisville Gas and Electric Company, 820 West Broadway, Louisville, Kentucky.

A copy of the application and testimony shall also be available for public inspection at the offices of the Kentucky Public Service Commission located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the commission's website at http://psc.ky.gov. Comments regarding the application may be submitted to the Public Service Commission through its website or by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602.

A copy of the Notice of Filing and the proposed tariff, once filed, shall also be available for public inspection on Louisville Gas and Electric Company's website at www.lge-ku.com, or through the Public Service Commission's website at http://psc.ky.gov.

Louisville Gas and Electric Company
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40232
502-627-4314

Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602
502-564-3940

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(2)
Sponsoring Witness: Edwin R. Staton

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.

a PPL company

RECEIVED

OCT 22 2014

PUBLIC SERVICE
COMMISSION

Louisville Gas and
Electric Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Ed Staton
Vice President
T 502-627-4314
F 502-217-2055
Ed.Staton@lge-ku.com

Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

October 22, 2014

RE: ***Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*** **– Case No. 2014-00______**

Dear Mr. DeRouen:

Please take notice that Louisville Gas and Electric Company ("LG&E") intends to file on or after November 26, 2014, a rate application for a general adjustment in its electric and gas rates, including changes to its electric and gas tariffs. The application will be supported by a fully forecasted test period ending June 30, 2016.

LG&E has contemporaneously filed a Request to Use Electronic Case Filing. Please assign this matter a case number and style and advise us of same so that it can be incorporated in the application and supporting testimony before filing with the Commission.

Sincerely,

Ed Staton

cc: Jennifer B. Hans, Esq.
Executive Director, Office of the Attorney General
Rate Intervention Division (via electronic mail)

LG&E
a PPL company

RECEIVED
OCT 22 2014
PUBLIC SERVICE
COMMISSION

Louisville Gas and
Electric Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Robert M. Conroy
Director, Rates
T 502-627-3324
F 502-627-3213
robert.conroy@lge-ku.com

Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

October 22, 2014

RE: ***Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*** **– Case No. 2014-00______**

Dear Mr. DeRouen:

Enclosed please find and accept a notice of election of use of electronic filing procedures in accordance with 807 KAR 5:001, Section 8. Louisville Gas and Electric Company intends to file on or after November 26, 2014, a rate application for a general adjustment in its electric and gas rates, including changes to its electric and gas tariffs.

Should you have any questions regarding the enclosed, please do not hesitate to contact me.

Sincerely,

Robert M. Conroy

Robert M. Conroy

cc: Jennifer B. Hans, 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, Louisville Gas and Electric Company gives notice of its intent to file an application for Adjustment of Its Electric and Gas Rates with the Public Service Commission no later than December 1, 2014 and to use the electronic filing procedures set forth in that regulation.

Louisville Gas and Electric Company further states that:

		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.	Pursuant to KRS 278.380, it waives any right to service of Public Service Commission orders by mail for purposes of this proceeding only;	☑	☐
5.	It or its authorized agents possess the facilities to receive electronic transmissions;	☑	☐
6.	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
Ed Staton	ed.staton@lge-ku.com

7.	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

Name: Robert M. Conroy
Title: Director, Rates
Address: 220 West Main Street
Louisville, KY 40202
Telephone Number: 502-627-3324

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(6)(a)
Sponsoring Witness: Kent W. Blake

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.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(6)(b)
Sponsoring Witness: Kent W. Blake

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.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(6)(c)
Sponsoring Witness: Kent W. Blake

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.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(6)(d)
Sponsoring Witness: Kent W. Blake

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:

LG&E acknowledges this requirement.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(6)(e)
Sponsoring Witness: Kent W. Blake

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:

LG&E acknowledges this requirement.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(6)(f)
Sponsoring Witness: Kent W. Blake

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.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(6)(f)
Page 1 of 1
K. Blake

LOUISVILLE GAS AND ELECTRIC COMPANY

Reconciliation of Capitalization and Rate Base

Line No.	Description	13 Month Average Total Company Balance	13 Month Average Electric	13 Month Average Gas
1	Rate Base Percentage (Schedule J-1.1/J-1.2)		82.61%	17.39%
2	Capitalization:			
3	Common Equity	$ 1,956,064,974		
4	Long-Term Debt	1,583,768,878		
5	Short-Term Debt	168,476,606		
6	Subtotal	$ 3,708,310,458	$ 3,063,435,269	$ 644,875,189
7	Adjustments to Capitalization:			
8	Trimble County Inventories		(4,427,703)	-
9	Investment in OVEC and Other		(1,133,706)	-
10	Environmental Compliance Plans		(943,105,359)	-
11	Demand Side Management Plans		(3,329,003)	(117,430)
12	Investment Tax Credits		34,606,995	149,969
13	Gas Line Tracker		-	(120,981,804)
14	Subtotal	-	(917,388,776)	(120,949,265)
15				
16	Total Adjusted Capitalization (Schedule J-1.1/J-1.2)	$ 3,708,310,458	$ 2,146,046,493	$ 523,925,924
17				
18	Assets per books not included in rate base:			
19	Net ARO Assets		(35,022,300)	(17,872,372)
20	Other Property and Investments	(22,341,077)	(17,519,409)	(3,687,962)
21	Cash and Temporary Investments	(16,835,843)	(13,908,090)	(2,927,753)
22	Accounts Receivable	(119,374,467)	(98,615,247)	(20,759,220)
23	Other Current Assets	(73,716,773)	(60,897,427)	(12,819,347)
24	Deferred Regulatory Assets	(289,858,474)	(239,452,086)	(50,406,389)
25	Other Deferred Debits	(5,380,802)	(4,445,081)	(935,721)
26	Accumulated Deferred Income Taxes	(236,988)	(195,776)	(41,212)
27	Subtotal	(527,744,424)	(470,055,414)	(109,449,976)
28				
29	Liabilities per books not included in rate base:			
30	Other Deferred Credits	52,309,143	14,499,855	3,052,324
31	Regulatory Liabilities	73,692,030	60,876,986	12,815,044
32	ARO Liabilities	89,981,044	74,333,341	15,647,704
33	Other Current Liabilities	391,775,856	323,646,035	68,129,821
34	Misc. Long-Term Liabilities	19,804,550	16,360,539	3,444,011
34	Accumulated Provision for Pension & Postretirement	46,110,576	38,091,947	8,018,629
35	Subtotal	673,673,200	527,808,702	111,107,533
36				
37	Capitalization per books not included in rate base:			
38	Debt Average Differences	(29,326,901)	(24,226,953)	(5,099,948)
39				
40	Items not included in rate base:			
41	Environmental Compliance Cash Working Capital		1,984,533	-
42				
43	Items included in rate base:			
44	Cash Working Capital Formula	91,985,540	80,312,762	9,688,245
45	Capitalization / Rate Base Allocation Differences	-	(11,838,434)	11,838,434
46	Subtotal	91,985,540	68,474,328	21,526,679
47				
48	Total Reconciliation	208,587,415	103,985,196	18,084,289
49				
50	Total Rate Base (Schedule B-1)	$ 3,916,897,873	$ 2,250,031,689	$ 542,010,213

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(a)
Sponsoring Witness: Edwin R. Staton

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:

- Victor S. Staffieri
- Paul W. Thompson
- Kent W. Blake
- David S. Sinclair
- John J. Spanos
- Dr. Martin Blake
- William E. Avera and Adrien M. McKenzie
- Edwin R. Staton
- J. Clay Murphy
- Robert M. Conroy

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(b)
Sponsoring Witness: Kent W. Blake

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.

Louisville Gas and Electric Company
Case N0. 2014-00372
Capital Expenditure Budget
Years 2014-2017

	Projected Capital Expenditures			
Category of Spend	**2014**	**2015**	**2016**	**2017**
Generation Capacity	32,697,702	13,919,608	10,970,191	1,140,426
Environmental	364,458,379	339,537,841	198,665,557	176,625,735
Generation	72,154,721	79,204,752	73,615,018	68,094,468
Transmission	34,964,371	15,765,201	12,067,731	25,212,355
Electric Distribution	68,678,728	74,991,784	78,323,969	87,448,200
Customer Services	5,710,749	4,621,669	3,820,823	3,555,020
IT & Shared Services	14,505,324	13,604,423	21,423,606	16,690,315
Total	**593,169,973**	**541,645,278**	**398,886,896**	**378,766,518**

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(b)

K. Blake

Louisville Gas and Electric Company
Case No. 2014-00372
Capital Expenditure Budget
Years 2014-2017

Category of Spend	**Projected Capital Expenditures** **2014**	**2015**	**2016**	**2017**
Gas Distribution	77,889,661	83,086,808	83,602,132	66,175,324
Customer Services	2,807,398	3,539,405	3,285,137	3,286,915
IT & Shared Services	3,905,818	3,659,498	5,739,115	4,495,466
Total	**84,602,877**	**90,285,711**	**92,626,383**	**73,957,705**

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(b)
Page 1 of 1
K. Blake

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(c)
Sponsoring Witnesses: Kent W. Blake / David S. Sinclair / Paul W. Thompson

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 LG&E'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 LG&E's forecast period are contained in the written direct testimony of Kent W. Blake and David S. Sinclair filed with LG&E's application and are also otherwise quantified, explained and properly supported in the following documents attached to this Filing Schedule. Certain information responsive to this request is being provided under seal pursuant to a Petition for Confidential Protection.

A. 2015 Financial Planning Modeling Process	Kent W. Blake
B. Annual Electric Sales & Demand Forecast Process	David S. Sinclair
C. 2015 Business Plan Electric Sales Forecast	David S. Sinclair
D. Annual Natural Gas Volume Forecast Process	David S. Sinclair
E. 2015 Business Plan Gas Volume Forecast	David S. Sinclair
F. Annual Generation & Off-System Sales Forecast Process	David S. Sinclair
G. 2015 Business Plan Generation and OSS Forecast	David S. Sinclair
H. 2015 – 2019 Business Plan LOB Presentation Template	Kent W. Blake
I. Line of Business Presentations	Kent W. Blake/Paul W. Thompson

Financial Forecast Modeling Process

Table of Contents

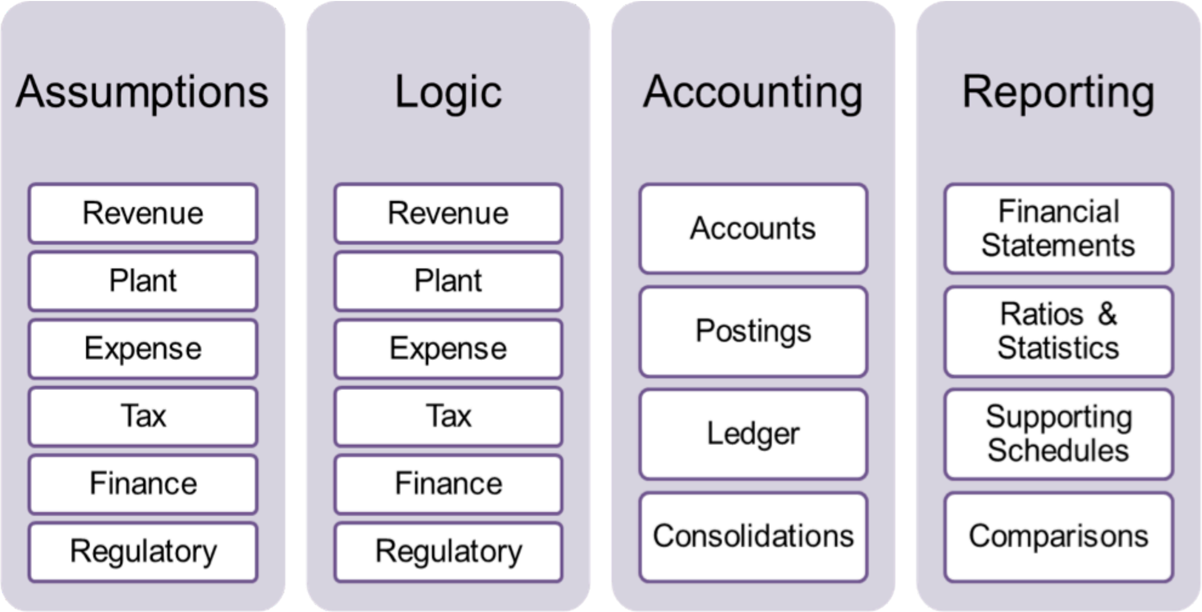
1. General

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 (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 company 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 functions, which function identical to a general ledger (see Planning Ledger flow chart below). Double-entry accounting of debits and credits is 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

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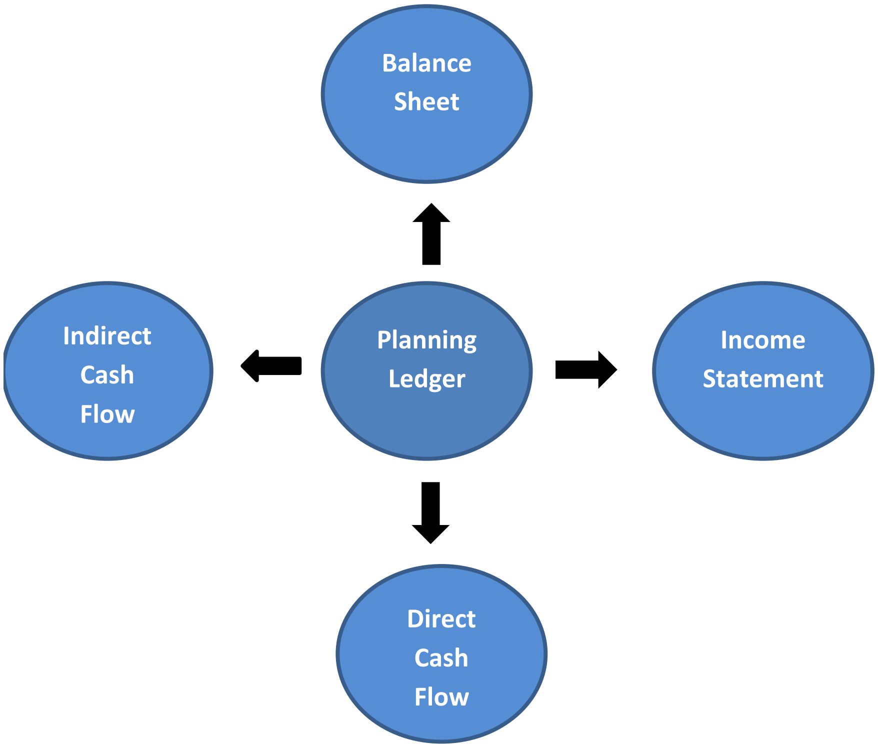
[1] http://utilitiesinternational.com/uiplanner-software/planning/

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



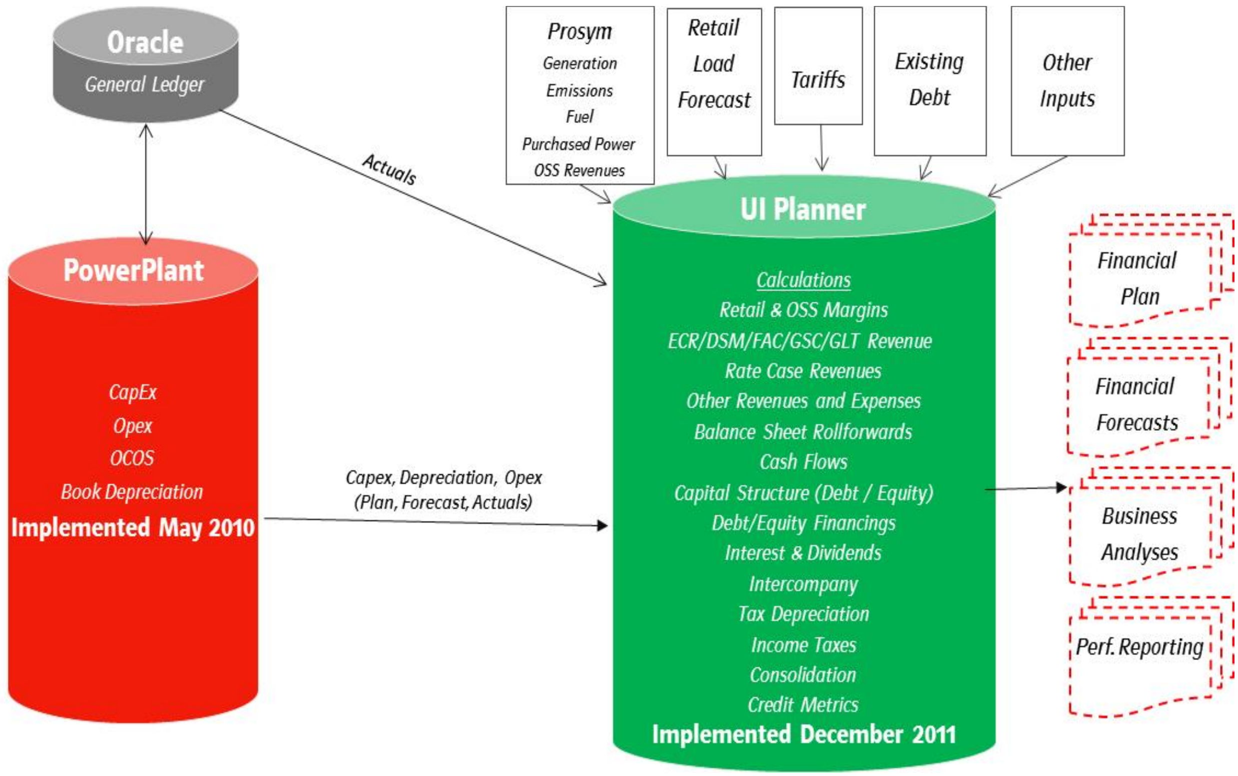
Each month actual balances are imported from the Oracle General Ledger (GL) to update UI with the latest balances and to compare the budget and revised forecast to actuals. The actuals imported into UI are compared to the trial balance in Oracle monthly to ensure completeness and accuracy.

Data in UI is entered via edit time data and housed within "cases". A collection of cases is grouped to create a "scenario". For example, the "2015 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 and who enters 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 scenario 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 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.

Financial Planning Software Flow Diagram



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 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. 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 PowerPlant, the Company’s corporate budgeting application. These details from PowerPlant 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 customer revenue, UI multiplies the number of customer times the customer charge. 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.

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 2015 Plan Electric Energy and Demand Forecast Process Document and the 2015 Plan Gas Volume Forecast Process Document, 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 in the business plan, by tariff
- Demand forecast by month and year, by tariff
- Customer count by month and year, by tariff

Allocators are used to convert the load from tariff rate to revenue class in UI. The tariffs are entered into UI from the tariff book based on the last rate case. UI then calculates energy, demand and customer revenues by revenue class. The revenues are then posted to the income statement.

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. Load serving (the forecast multiplied by the associated rates)
    a. The forecasts are provided by the customer for 2015-2020. If a customer did not supply the utilities with a forecast, a one percent annual escalator is applied to the average of the past 5 years for that customer.
    b. Rates are projected to increase three percent annually.
        i. For the 2015 BP, three percent was used for rate projections based on the historical trending and audits performed on the OATT rate.
        ii. The annual rate change occurs each June.
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.
    b. Short-term firm service– is projected based on annual historical revenue and escalated three percent annually.

c. Rates are projected to increase three percent annually.
   i. For the 2015 BP three percent was used for rate projections based on the historical trending and audits performed on the OATT rate.
   ii. The annual rate change happens June of each year.

The projected intercompany transmission revenue is imported into UI from PowerPlant.

The transmission rates are documented in the LG&E and KU Open Access Transmission Tariff, 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 and late payment charges
- Reconnect, gas meter and inspection charges and temporary service charges
- Rent from electric and gas property
- Coal sales
- Returned check charges

For the above items, except for coal sales, the miscellaneous revenue is calculated by utilizing the historical trends and applying an inflation factor to the next five years, which is then uploaded into UI. A coal sale is essentially revenue derived from the transportation of coal for a third party. The Company does not purchase the coal or take possession of it; the Company utilizes an existing barge contract to transport the customer's coal. The revenues are based on the contract with the customer, which incorporates costs of the barging, trucking, labor hours, maintenance, plus the profit.

3. Mechanisms

Background

The Kentucky Public Service Commission has adopted a series of regulatory mechanisms that reduce regulatory lag and provide for timely recovery of and a return on, as appropriate, 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 and on 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 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 PowerPlant 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 PowerPlant to the previous' month ending rate base, adjusted for depreciation, an increase/decrease in deferred taxes. A return on the 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 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 LG&E's gas main replacement program, gas service lines and risers.

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 PowerPlant 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 and O&M is 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 OSS electric generation, company use, and unrecoverable intercompany sales. The total recoverable fuel expenses is then compared to the base fuel revenues calculated by multiplying the base fuel rate times the megawatt hour sales by jurisdiction. The over/under is booked to The Fuel Adjustment Clause.

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, Off-System Sales (OSS) and Other Cost of Sales (COS)

Generation forecast and OSS

The PROSYM application is used to calculate generation and OSS. See the 2015 Plan Generation and Off-System Sales Forecast Process Document, 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. The OSS revenues are included in the Total Electric Revenue section of the Income Statement.

Power Purchase Agreement

Power purchase agreement costs are based on the contracts set with the third party power producer. 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 fuel adjustment clause and the capacity and demand cost through base rates.

Other Cost of sales (COS)

OCOS inputs come from PowerPlant and PROSYM. Off system sales, purchased power, and fuel related costs come from PROSYM, as noted above. Emissions, mechanism (DSM, ECR, ECR, GSC, and GLT), and transmission related costs come from PowerPlant.

Other electric cost of sales includes variable production consumables used by the power plants in the generation of electricity. For coal units, this includes the cost of operating environmental controls and the cost of controlling coal combustion residuals. 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 PowerPlant 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.

5. Operations & Maintenance (O&M) (Non-fuel)

Operations and Maintenance expenses are included as part of the Income Statement and reflect the labor and nonlabor 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 PowerPlant for consolidation. This information is then uploaded to UI for review and approval.

Labor Cost

The Company's current labor base is obtained from PeopleSoft annually in May. 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 PowerPlant with the labor forecast being available by mid-May. The forecast includes full-time and part-time regular employees, summarized by employee type and expenditure organization.

Updates to the forecast in PowerPlant are due in early June. 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-June. 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 lines of business areas 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.

Planned changes in costs within accounts can be specifically escalated according to contracted 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.

Approved labor and non-labor rate inflationary assumptions;

Labor and non-labor rates	**2015**	**2016**	**2017**	**2018**	**2019**
Labor rate increases	3%	3%	3%	3%	3%
Non-labor rate increase	2%	2%	2%	2%	2%

- The labor rates are subject to possible adjustment pursuant to union negotiations. The rate increase assumptions are based on annual benchmarking studies performed. Current results from those studies support a 3% planning assumptions for labor increases.
- Non-labor – general inflationary increase of 2% for assumed growth in expenses not specifically tied to contracts or fixed amounts.

6. Other Income Statement Items

Other income and expense items not included above include:

- Donations
- Employee Recognition costs (non-safety related)
- Non-Utility Revenues and Expenses
- Interest and dividends received

For the above items, the income and expenses are calculated by utilizing the historical trends and applying an inflation factor to the next five years, which is then uploaded into UI.

7. 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 includes;

- tax depreciation,
- book depreciation,
- regulatory asset & liability movement,
- pensions/post-retirements,
- capitalized interest, and
- Section 199, etc.

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 and a basis reduction due to the Trimble County 2 investment tax credit (ITC). Additionally, the ITC amortization is manually entered into UI based on ITC amortization schedules maintained by the Tax department.

Property Taxes

Property taxes are estimated annually based on net book asset values as of December 31 of the previous year and includes 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 results in large cash payments during the fourth quarter of a calendar year. Property tax data is imported into UI by FERC account by utility.

The primary source of data used to calculate the estimates is within the UI report labeled “KY Plant Account” report from UI Planner. 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.

Property taxes related to ECR projects are calculated separately for ECR mechanism purposes.

8. <u>Capital</u>

Background

Each line of business 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 into and maintained in PowerPlant.

The Senior Officers through their roles as members of the Investment Committee approve the Capital plan each year. The Capital plan is presented to the Investment Committee for approval by a subcommittee referred to as the Resource Allocation Committee (“RAC”). The RAC includes leaders from multiple business lines 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 PowerPlant 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.

9. Closings to Plant in Service and Depreciation

After Capital Spending is booked to CWIP on the balance sheet, UI gets an import from PowerPlant by Plant account to determine additions to Plant in Service.

UI also imports a Depreciation forecast that is done based on capital plan, including property classifications and in service dates, and approved depreciation rates.

The approved depreciation rates 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 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 PowerPlant.

The plant in service ending balance for the most recent month of actuals is pulled out of PowerPlant. 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 that means that in the first month of an addition or retirement to plant in service, we divide the 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 forecast and the estimated in service dates on those assets. If the asset is already in service and additional money is spent on those assets, it 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 PowerPlant, on which date the entire CWIP balance is moved to plant in service.

10. Dividends, Debt and Equity

Dividends:

LG&E and KU pay dividends to its parent, LKE, on a quarterly basis. The dividend is calculated in the model using a payout assumption equal to 65% of the previous quarter’s net income.

Capital Structure:

LG&E and KU strive to maintain a ratio of 53 percent equity and 47 percent 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 percent equity and 47 percent debt. The Utilities Parent 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 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 Treasury 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 Companies have a general modeling limit of $300 million on the commercial paper balances. The maximum can be changed after discussions with Treasury and the CFO. Once the maximum short-term debt is reached, long-term debt is issued in increments of $250 million or more and the balancing starts again the next month. The $250 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: 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 $250 million or more. Capital contributions in the form of equity from LKE are used to maintain the proper equity: debt ratios. LKE receives capital contributions from PPL to fund the utilities cash needs.

All short-term rates and interest on cash balances are based on a spread to the three-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.

11. <u>Pension & Postretirement</u>

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 plan based on management's assumptions. These assumptions include the annual discount rate, the expected return on plan assets, the expected wage increase, the annual mortality rate table, funding policy and other assumptions as needed.

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 PowerPlant. These amounts are spread by month consistent with the timing of the labor budget.

Pension funding occurs annually in January while postretirement funding is quarterly with the 401(h) portion of the funding occurring all in the fourth quarter.

12. Other Balance Sheet assumptions

a. Balances

The actual August 2014 balances from the balance sheet were the starting point for this forecast. The amounts were imported from Oracle General Ledger (GL) and imported through the Day 6 process, which imports the actuals from the GL by running a query and exporting the details into Excel. A detailed and thorough balancing process is also done to ensure all details from Oracle translate appropriately into UI.

b. Cash

As noted above minimum cash balances are set each year at $5 million per utility. This is based on discussion with Treasury and if UI determines insufficient cash balances based on the projected activity short-term debt is issued.

c. 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.

d. 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 August 2014 balance and is adjusted for disposals.

e. Prepayments affecting the balance sheet include insurance, PSC Fees, and 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 the PSC fees, 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.

f. Unamortized debt expenses

For each bond issued, the Company incurs debt issuance costs, which are amortized over 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 calculated in excel 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.

g. Regulatory Assets and Liabilities

Adjustments to the regulatory assets and liabilities are obtained from schedules produced by the Company's Accounting Department, reflecting amortization rates previously approved by the Commission. These schedules include storm costs, rate case expenses, MISO exit fees, interest rate swaps, deferred income taxes, 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 liabilities is performed using UI logic.

h. Accounts Payable

The forecasted balances of accounts payable is a function of the capital and O&M spend, adjusted for some payment lag.

i. Asset retirement obligations (ARO)

The calculation of accretion expense is performed in an automated fashion within the PowerPlant Fixed Asset System. Accretion expense is calculated by taking the beginning ARO liability balance multiplied by the discount rate for each ARO.

Annual Electric Sales & Demand Forecast Process

PPL companies

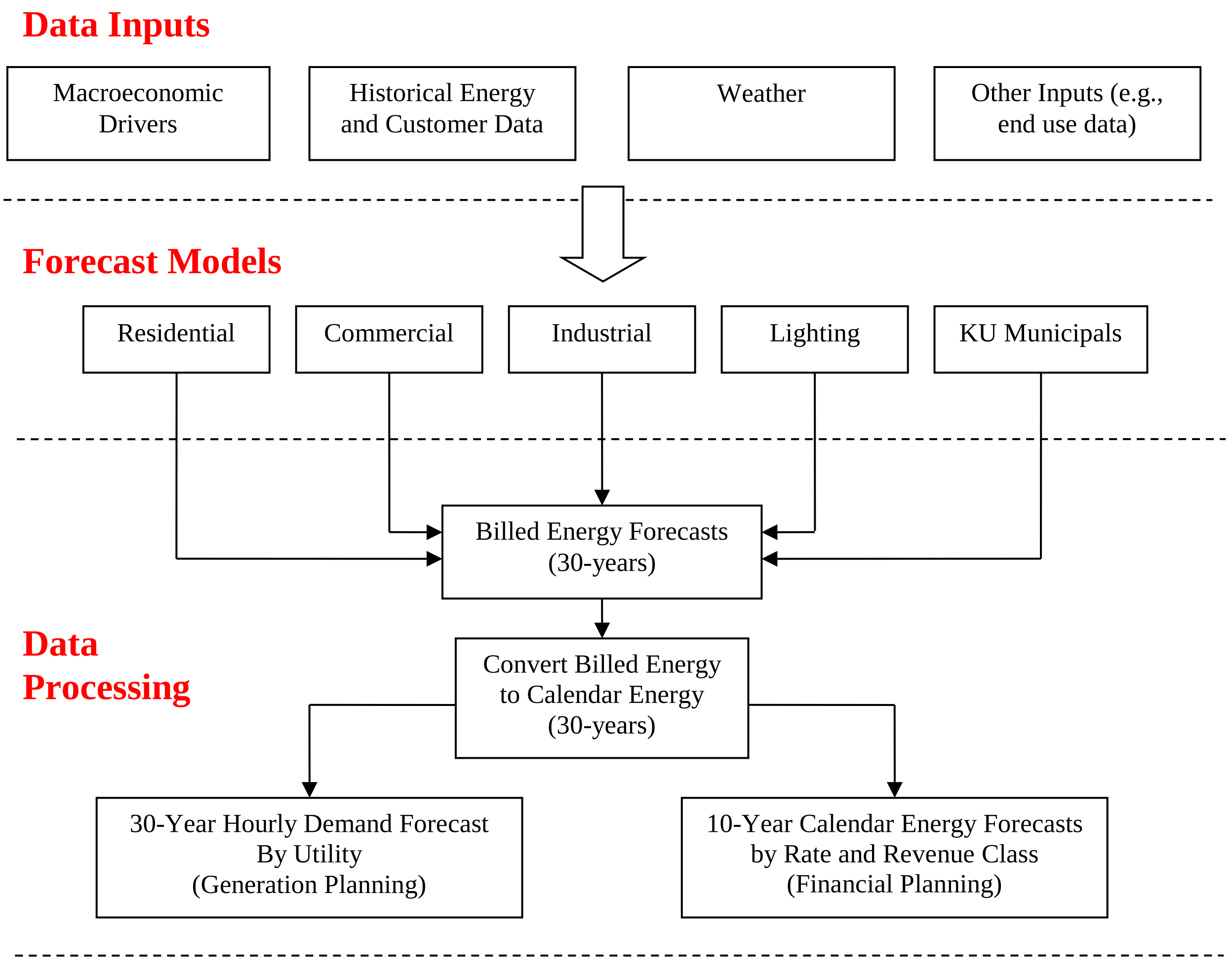
Sales Analysis & Forecasting
September 2014

Table of Contents

1. Introduction

The Sales Analysis & Forecasting group develops the annual Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies") sales and demand forecasts. These forecasts serve as foundational inputs for the Generation Planning department's annual Generation Forecast and the Financial Planning department's annual Business Plan. This document summarizes the processes used to produce the annual sales and demand forecasts. The forecast process can be divided into three 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 cycle forecasts, class-level electricity price series, and residential appliance shares and efficiencies.

The input data is used to specify various forecast models. The Companies' energy forecast is comprised of twenty-nine forecast models. 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 energy forecasts on a monthly billed basis.[1] In the third part of the forecast process, energy data from the forecast models is processed to meet the needs of forecast end users. The monthly billed energy forecasts must first be converted to calendar month (or "as-used") forecasts. The billed and calendar sales forecasts are allocated by rate and revenue class[2] for the Financial Planning department. In addition, a forecast of hourly energy requirements[3] is developed for the Generation Planning department.

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 is discussed in more detail in the following sections.

---

[1] All customers are assigned to one of 20 billing cycles. A billing cycle determines what time of the month a customer's meter is read. Because most billing cycles do not coincide precisely with the boundaries 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. See Appendix D.

[3] Energy requirements are equal to sales plus transmission and distribution losses.

2. 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.

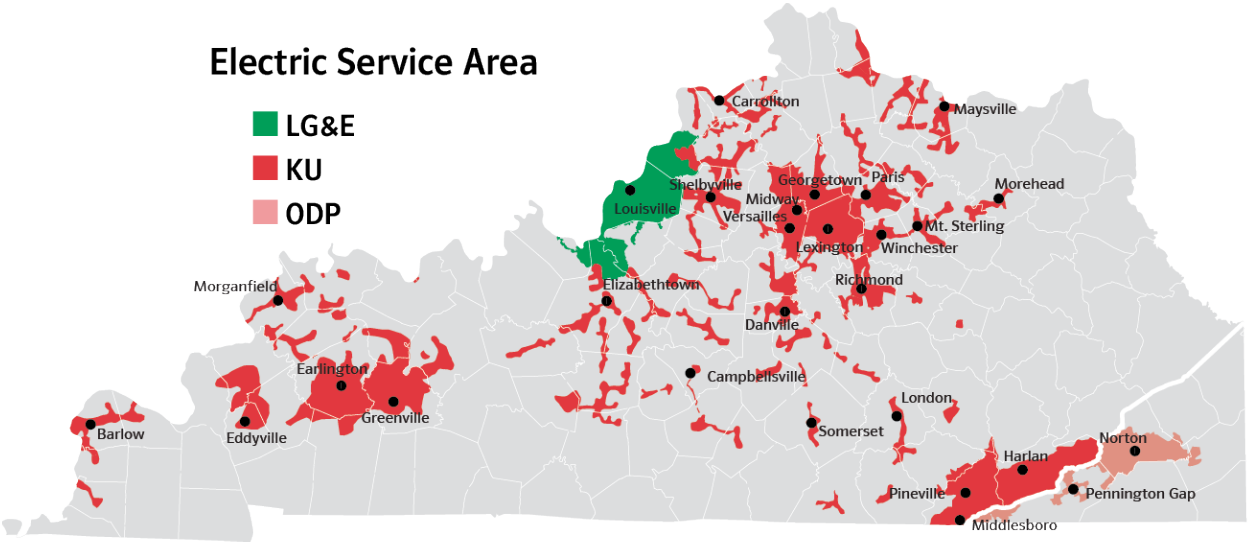
Table 1 – Summary of Forecast Data Inputs

Data	***Source***	***Format***
State Macroeconomic and Demographic Drivers (e.g., Employment, Wages, Households, Population)	IHS Global Insight, Kentucky Data Center	Annual or Quarterly by County – History and Forecast
National Macroeconomic Drivers	IHS Global Insight	Annual or Quarterly – History and Forecast
Personal Income	IHS Global Insight	Annual by County
Weather	NOAA	Daily HDD/CDD Data by Weather Station – History
Bill Cycle Schedule	Revenue Accounting	Monthly Collection Dates – History and Forecast
Appliance Saturations/Efficiencies	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	LG&E, KU and ODP – Monthly by Rate Group
Number of Customers History	CCS Billing System	LG&E, KU and ODP – Monthly by Rate Group

2.1 Service Territory-Specific Macroeconomic Forecasts

IHS Global Insight 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 and KU/ODP electric service territories.

Figure 2 – LG&E and KU/ODP Service Territory Map



Two counties make up the majority of the LG&E service territory, while KU serves customers in parts of over 70 counties;[4] ODP's service territory includes parts of five counties in southwestern Virginia. Service territory-specific macroeconomic forecasts are created by aggregating the applicable county-specific forecasts for the counties in LG&E, KU, and ODP service territories.

2.2 Software Tools

The following software packages are used in the forecast process:

- Microsoft Office: Excel, PowerPoint, Access
- SAS
- Itron Metrix ND
- @Risk

2.3 Processing of Weather Data

Weather is a key explanatory variable in the electric forecast models. The weather dataset from the National Oceanic & Atmospheric Administration's (NOAA) National Climatic Data Center (NCDC) contains temperatures (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.[5] Each of these processes is summarized below.

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[4] Appendix A contains a list of the counties in each service territory.

[5] "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.

2.3.1 Historical Weather by Billing Month

The methodology 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 cycle.[6] Each historical billing month consists of 20 cycles. The Companies' historical meter reading schedule contains the beginning and ending date for each billing cycle.
2. Average the billing cycle total HDDs and CDDs by billing month.

2.3.2 Normal Weather Forecast by Billing Month

The methodology used to produce the forecast of normal weather by billing month includes the production of a daily forecast of normal weather. The methodology used to develop the daily forecast (summarized in Steps 2-5) is consistent with the methodology used by the NCDC to create its daily normal weather forecast.[7] 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 about 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 cycle through the end of the forecast period. In this step, sum the HDD and CDD values by billing cycle. Use the February 28 weather data as a proxy for February 29 when billing cycles include leap days.
6. Average the billing cycle totals by billing month.

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[6] Weather data in the electric forecast is taken from the weather stations at the Bowman Field Airport (LOU) in Louisville, Bluegrass Field Airport (LEX) in Lexington, and Tri-Cities Airport in Tennessee.

[7] The NCDC derives daily normal values by applying a cubic spline to a specially prepared series of the monthly normal values.

2.3.3 Daily Normal Weather Forecast

A daily normal weather forecast is used to produce the forecast of hourly energy requirements (see Section 4.3). The daily normal weather forecast is based on twenty years of historical weather data. The following process is used to compute the daily normal weather forecast:

1. For each company, month and year, sort the days from coldest to warmest. For a given January, the coldest day has a "rank" of one; the warmest day has a rank of 31.
2. Average the daily temperatures by company, month and rank. In the daily normal weather forecast, the average temperature for the coldest January day is computed as the average of the coldest January day in each of the past twenty years. The average temperature for the second coldest January day is computed as the average of the second coldest January day in each of the past twenty years, and so on.
3. Allocate these temperatures to days throughout the month, using a process to ensure that the top ranked temperature (and therefore, peak day) falls on a weekday, when industrial and commercial customers are most likely to be consuming higher amounts of energy.

3. Forecast Models

The Companies' energy forecast is comprised of twenty-nine forecast models. All models forecast sales and the number of customers on a monthly basis. These forecasts are discussed in detail in the following sections.

3.1 Residential Forecast

The Residential forecast is comprised of three classes: KU Residential, LG&E Residential, and ODP Residential. The Residential forecast includes all customers on the Residential Service (RS) and Volunteer Fire Department (VFD) rate schedules. Residential sales are forecasted for each company as the product of a customer forecast and a use-per-customer forecast.

3.1.1 Residential Customer Forecast

The number of residential customers is forecasted by company 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 Global Insight and the Kentucky Data Center.

3.1.2 Residential Use-per-Customer Forecast

Average use-per-customer is forecast using a Statistically-Adjusted End-Use (SAE) Model. Such a model combines an econometric model – that relates monthly sales to various explanatory variables such as weather and economic conditions – 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.

$$\text{Use-per-Customer} = a1*XHeat + a2*XCool + a3*XOther$$

The heating, cooling and other components (the X variables) are based on various input variables including 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 discussion of each of these components and the methodology used to develop them is contained in Appendix B.

3.2 Commercial Forecast

The Commercial forecast is comprised of ten rate class models: KU General Service, KU Large Commercial, KU All-Electric Schools, LG&E General Service, LG&E Primary Commercial, LG&E Secondary Commercial, ODP Large Commercial, ODP General Service, ODP Schools and ODP Municipal Pumping. Each of these rate classes is forecasted separately on a monthly basis over the forecast period. The period of historical data used in the models varies based on each rate class's history.

3.2.1 KU, LG&E, and ODP General Service

The general service forecasts include all customers on the General Service (GS) rate and are comprised of two separate forecasts: a sales forecast and a customer forecast. The former employs a Statistically-Adjusted End-Use model (SAE), which defines energy use as a function of energy used by heating equipment, cooling equipment, and other equipment (see description under Residential, 3.1.2 and Appendix C.

The customer forecasts are a function of the Residential customer forecasts which incorporate Household and Population growth since, historically, household growth, population growth, and residential customer growth are highly correlated.

3.2.2 KU Large Commercial

The KU Large Commercial forecast includes all customers on the PS Secondary and TOD Secondary rates. Sales to PS Secondary customers are modeled as a function of heating and cooling degree days, Retail and Wholesale Employment indices, and binary variables which account for anomalies in the historical data.

3.2.3 KU All-Electric Schools (AES)

The KU All-Electric Schools forecast includes all customers on the All-Electric School rate schedule. KU AES sales are modeled as a function of the number of KU households, weather, and binary variables to account for anomalies in the historical data.

3.2.4 LG&E Commercial

The LG&E Commercial forecast includes all customers on the CPS Primary, CPS Secondary, CTOD-Primary, and CTOD-Secondary rate schedules. The Primary and Secondary rates are forecasted separately to capture similar energy usage patterns and levels. LG&E Commercial sales are forecast in total as a function of weather, specific economic drivers, the number of customers, and other binary variables to account for anomalies in the historical data.

3.2.5 LG&E Special Contracts

The LG&E Special Contracts forecast includes Louisville Water Company and Fort Knox. These customers are forecasted individually, based on information and feedback from the customers and major account representatives.

3.2.6 ODP Schools

The ODP Schools forecast includes all customers on the School Service (SS) rate schedule. Sales to the ODP schools are modeled as a function of the number of households, weather, and binary variables.

3.2.7 ODP Municipal Pumping

The ODP municipal pumping forecast consists of customers on the Water Pumping Service rate schedule. ODP municipal pumping sales are forecasted using a trend model based on recent sales.

3.3 Lighting Forecast

The Lighting forecast is comprised of seven rate classes: LG&E LES and TES, KU LES and TES, and unmetered Street Lighting for each company. All Lighting-related energy is forecasted using a trend model based on recent sales.

3.4 Industrial Forecast

A relatively small number of customers in an industrial rate can make up a significant portion of the total sales for that rate. Furthermore, any expansion or reduction in operations by the larger industrial customers can significantly impact the Companies’ load forecast. Therefore, the Companies work directly with the largest industrial customers (Major Accounts) to develop their forecasts. The large individually forecasted customers are removed from the historical energy sales data by rate, while the remaining customers are forecasted using econometric models described below. The total rate forecast is the combination of the individually forecasted customers and the customers forecasted using econometric models.

3.4.1 KU Industrial Forecast

The KU industrial forecast is comprised of three forecast models. The forecast models are aggregated by rate codes by voltage level.

3.4.1.1 Primary

The PS Primary, TOD Primary, and LTOD Primary rates are forecasted together, then allocated into individual rate forecasts using historical sales ratios. The Primary forecast includes all customers that take service at the primary distribution voltage. Sales to Primary customers are modeled as a function of an industry-weighted Industrial Production Index and weather.

3.4.1.2 Retail Transmission Service

The RTS forecast includes all retail customers previously on a Transmission-level rate. Since a large component is sales to Mine Power customers, the Wood-MacKenzie forecast of Eastern and Western Kentucky coal production is used as a driver. In recent years, the demand for lower sulfur eastern Kentucky coal has declined while the demand for higher sulfur western Kentucky coal has increased. Therefore, two mining forecasts are developed to more accurately reflect this trend. The two forecasts are combined to form the final KU RTS forecast.

3.4.1.3 Fluctuating Load Service

The FLS forecast includes one customer, the North American Stainless Arc Furnace. The FLS forecast is developed based on discussions with the customer.

3.4.2 LG&E Industrial Forecast

The LG&E industrial forecast consists of three forecast models: Industrial Primary (Power Service and Time of Day), Industrial Secondary (Power Service and Time of Day), and Retail Transmission Service. Each of these rate classes is forecasted separately with specific economic drivers and weather.

3.4.2.1 Industrial Primary (Power Service and Time of Day)

The Industrial Primary forecast includes all customers on Industrial Primary rates. Monthly sales are modeled as a function of an industry-weighted Industrial Production Index, number of customers, and weather.

3.4.2.2 Industrial Secondary (Power Service and Time of Day)

The Industrial Secondary forecast includes all customers on Industrial secondary rates. Monthly sales are modeled as a function of an industry-weighted Industrial Production Index, number of customers, and weather.

3.4.2.3 Retail Transmission Service

The RTS rate consists of both individually forecasted major accounts and smaller customers. The major accounts customer forecasts are developed with input from the major account managers and customer input. The remaining smaller customer forecasts are developed using a trend model based on recent sales.

3.4.3 ODP Industrial Forecast

The ODP industrial forecast is a combined forecast of PS Primary, TOD Primary, and RTS rates. Industrial sales are forecasted as a function of the Eastern Kentucky Wood-MacKenzie index, number of customers, and weather.

3.5 KU Municipal Forecast

KU municipal forecasts are provided by various consultants for different cities. These forecasts are reviewed for consistency and compared to historical sales and trends. Questions or concerns regarding the forecasts are sent to the municipal customers and their consultants, if applicable. Any subsequent revisions received from the municipal customers are incorporated into the forecasts.

3.6 Billed Demand Forecast

The Billed Demand forecasts are based on historical demand factors, where the demand factor is the billed demand volume divided by the billed sales volume. The historical demand factor is then multiplied by the sales forecast for rates that have billed demand components.

4. Data Processing

The Companies' customers are assigned to one of 20 billing cycles. Because most billing cycles do not coincide directly with the boundaries 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. Most historical sales data is recorded on a billed basis. As a result, most energy forecasts are produced initially on a billed basis. To meet the needs of the forecast end users, the billed energy must be further processed. The following processes are discussed in more detail in the following sections:

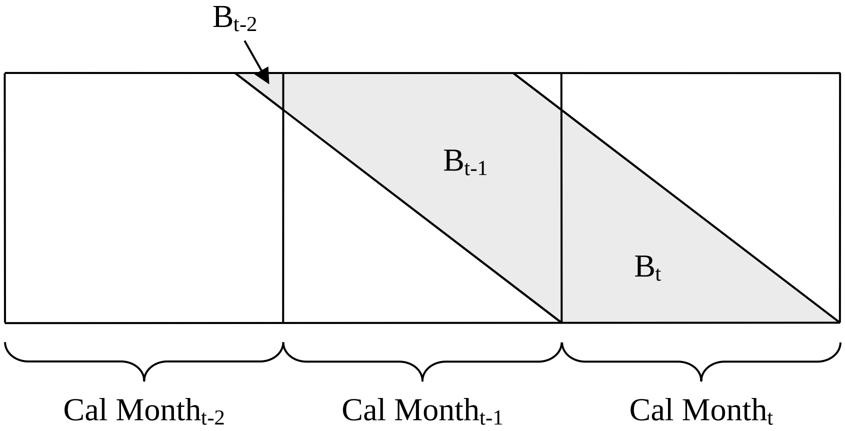
1. Billed-to-Calendar Energy Conversion
2. Rate Code and Revenue Class Allocation
3. Hourly Energy Requirements Forecast

4.1 Billed-to-Calendar Energy Conversion

Since the billed volumes for most forecast classes do not coincide directly with the boundaries of calendar months, most class forecast volumes must be converted from a billed to calendar basis. Forecasts for the following rate classes do not have to be converted from a billed to calendar basis: LG&E Special Contracts, KU FLS and KU municipals. The customers in these forecast classes are billed on a calendar-month basis.

The shaded area in Figure 3 represents a typical billing month (B). Area B_t represents the volumes in the billing month that were consumed in the current calendar month (time = t). Area B_{t-1} represents the volumes in the billing month that were consumed in the previous calendar month (time = t-1). Area B_{t-2} represent the volumes in the billing month that were consumed in the calendar month two months prior to the current month (time = t-2).[8]

Figure 3 – Billed and Calendar Energy



Using historical hourly energy requirements data by company (KU/ODP, LG&E) to obtain calendar monthly allocation ratios, the annual billed sales forecasts (by company) are allocated into months using the calendar monthly allocation ratios. This yields monthly calendar sales forecasts by company. These monthly calendar sales by company are then allocated into rate classes using the ratio of billed sales by rate to total billed sales. Figure 4 shows a diagram of the process.

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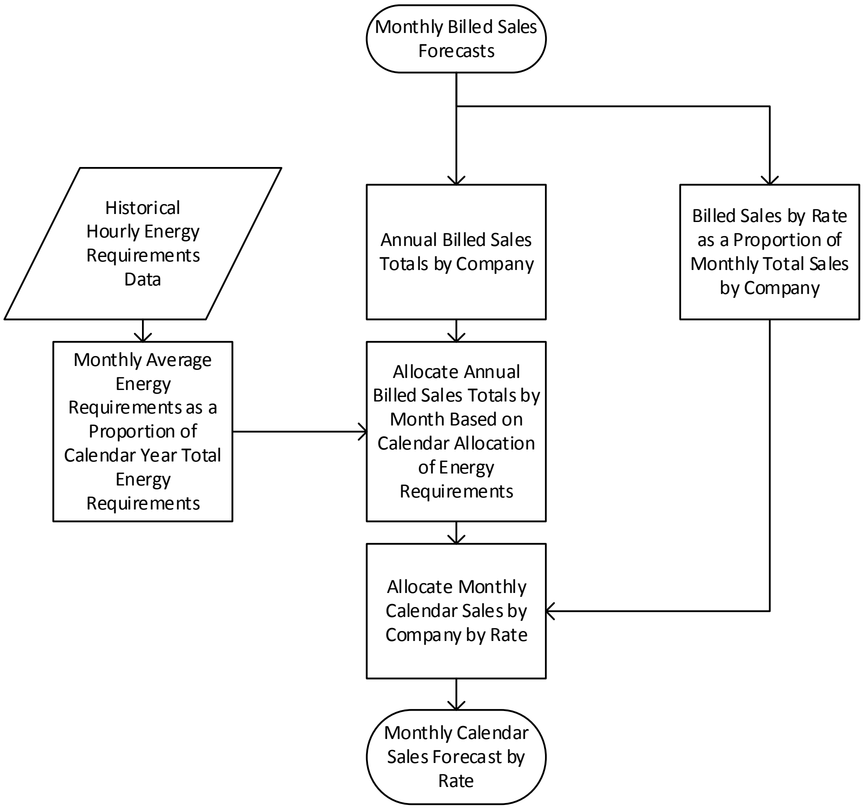
[8] Not all billing months include volumes that were consumed in the calendar month two months prior to the current month.

Figure 4 – Billed to Calendar Allocation



4.2 Rate Class to Revenue Class Allocation

To meet revenue forecasting requirements, the billed and calendar energy forecasts must be allocated by rate class and revenue class. Revenue class is a higher level grouping that aggregates portions of each rate class into a corresponding revenue class. All rate classes are allocated to one of the following revenue classes:

- Residential
- Commercial
- Industrial
- Public Authority
- Wholesale
- Lighting

This information is used by the Financial Planning department to develop a forecast of revenues for the planning period. Billed and calendar forecasts are allocated by rate class to revenue class using a set of monthly allocation ratios. These ratios are derived based on historical sales data from CCS for energy, demand, and customers by rate class and revenue class.

4.3 Hourly Energy Requirements Forecast

The hourly energy requirements forecast is developed from the final sales forecasts. The Generation Planning department uses the hourly energy requirements forecast to develop resource expansion plans and a forecast of generation production costs. This forecast is developed in 3 steps.

4.3.1 Step 1

In Step 1, the monthly calendar sales forecasts by company are allocated to hours using historical hourly requirements data. The following process is used to develop load shapes:

1. Compute average hourly shapes by company, month and day type (day of week/holiday) using historical hourly data by company.
2. For each month, daily average load models are developed as a function of weather and day type.
3. Using the average profiles from #1, the weather and day type parameters from #2, and a daily normal weather forecast (see Section 2.2.3), develop load shapes for each company by month and day type.

4.3.2 Step 2

In Step 2, transmission and distribution losses are added to the hourly sales forecast (from Step 1) to determine energy requirements. Losses are estimated as a percentage of sales based on the month, with higher losses in peak months as well as higher losses at peak times.

4.3.3 Step 3

In Step 3, an hourly forecast, grossed-up for losses, of the Companies' dispatchable DSM program (i.e., Direct Load Control) is used to reduce the hourly energy requirements forecast.

The dispatchable DSM program can be called upon by the Generation Dispatch group to reduce system demand during peak summer periods. The dispatchable program is incorporated into the hourly demand forecast consistent with the way the Generation Dispatch group uses this program.

PPL companies

2015 Business Plan
Electric Sales Forecast

July 24, 2014

Major assumptions and changes vs. 2014 Plan

- *Unfavorable inputs*
  - *Further decline in eastern Kentucky mining*
  - *Departure of 10 KU municipal customers by 2019*
  - *Lower household growth rate for KU*
  - *More rapid adoption of high efficiency lighting*
- *Favorable inputs*
  - *Personal income and wholesale employment slightly higher*
  - *Major account forecasts higher*
- *Overriding theme*
  - *Economic growth still slow*

LG&E KU
PPL companies

Municipal terminations result in ~320 MW load reduction in May 2019

- *2015 Plan assumes that Bardstown and Nicholasville remain KU customers*
- *Significant load impact occurs in May 2019 with departure of eight larger municipal customers; two prior departures have less impact*
  - *Benham: August 2016 (1 MW load)*
  - *Paris: May 2017 (3 MW firm)*

LG&E KU
PPL companies

Balance of year 2014 forecast 240 GWh below 2014 Plan

2014 Combined Company Plan to Plan					
Period	2013 WN Actuals (GWh)	2014 Plan (GWh)	2015 Plan (GWh)	Variance 2014-2015 Plan (GWh)	Pct Var
Jan - May (WN Actuals)	*13,360*	*13,302*	*13,327*	*25*	*0.2%*
*June**	*2,742*	*2,984*	*2,919*	*(65)*	*-2.2%*
July	*3,105*	*3,303*	*3,245*	*(58)*	*-1.8%*
August	*3,150*	*3,331*	*3,293*	*(38)*	*-1.1%*
September	*2,668*	*2,764*	*2,704*	*(59)*	*-2.1%*
October	*2,516*	*2,525*	*2,492*	*(33)*	*-1.3%*
November	*2,561*	*2,551*	*2,522*	*(29)*	*-1.1%*
December	*2,892*	*2,922*	*2,900*	*(22)*	*-0.7%*
Total	*32,994*	*33,681*	*33,401*	*(280)*	*-0.8%*

** June 2014 is actual value non-WN in 2015 Plan*

PPL companies

2015 Plan with and without municipal customers

- *Energy forecast with municipal customers (all years)*

	Total Company Sales (GWh)				KU/ODP Sales (GWh)				LG&E Sales (GWh)			
	2015 Plan*	2014 Plan	Delta	% Change	2015 Plan	2014 Plan	Delta	% Change	2015 Plan	2014 Plan	Delta	% Change
2014	33,442	33,681	(239)	-0.7%	21,585	21,774	(189)	-0.9%	11,857	11,908	(50)	-0.4%
2015	33,394	33,845	(451)	-1.3%	21,416	21,860	(445)	-2.0%	11,978	11,985	(6)	-0.1%
2016	33,634	34,092	(459)	-1.3%	21,544	22,016	(472)	-2.1%	12,090	12,077	13	0.1%
2017	33,918	34,307	(390)	-1.1%	21,706	22,159	(452)	-2.0%	12,211	12,148	63	0.5%
2018	34,254	34,593	(340)	-1.0%	21,924	22,340	(416)	-1.9%	12,330	12,253	77	0.6%
2019	34,559	34,888	(329)	-0.9%	22,123	22,537	(413)	-1.8%	12,436	12,351	85	0.7%

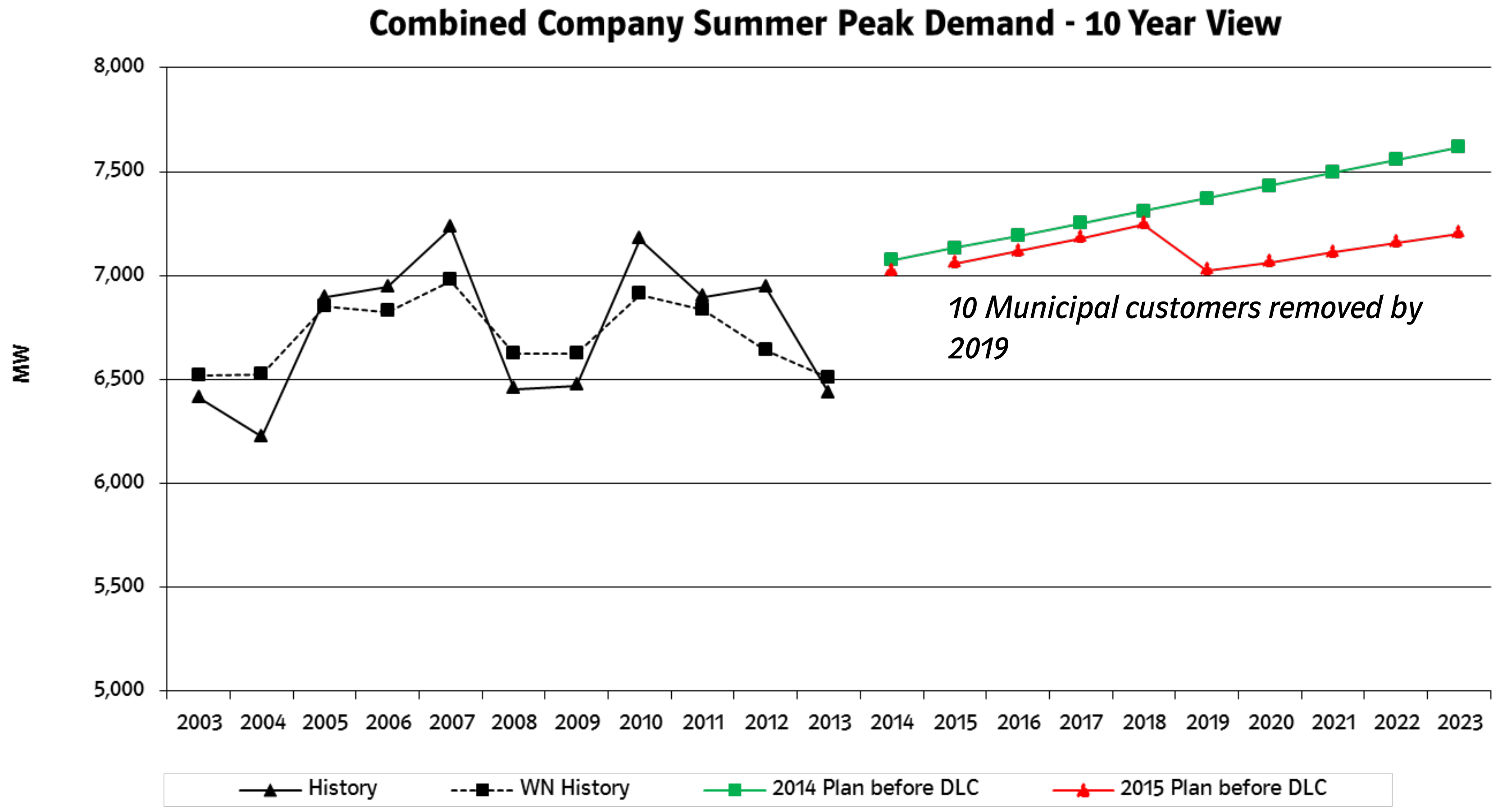
- *2015 BP: Municipals exit per schedule in 2016-2019*

	Total Company Sales (GWh)				KU/ODP Sales (GWh)				LG&E Sales (GWh)			
	2015 Plan*	2014 Plan	Delta	% Change	2015 Plan	2014 Plan	Delta	% Change	2015 Plan	2014 Plan	Delta	% Change
2014	33,442	33,681	(239)	-0.7%	21,585	21,774	(189)	-0.9%	11,857	11,908	(50)	-0.4%
2015	33,394	33,845	(451)	-1.3%	21,416	21,860	(445)	-2.0%	11,978	11,985	(6)	-0.1%
2016	33,632	34,092	(461)	-1.4%	21,542	22,016	(474)	-2.2%	12,090	12,077	13	0.1%
2017	33,868	34,307	(439)	-1.3%	21,656	22,159	(502)	-2.3%	12,211	12,148	63	0.5%
2018	34,181	34,593	(412)	-1.2%	21,852	22,340	(489)	-2.2%	12,330	12,253	77	0.6%
2019	33,514	34,888	(1,374)	-3.9%	21,078	22,537	(1,459)	-6.5%	12,436	12,351	85	0.7%

* *In 2015 Plan forecast, 2014 value is a weather-normalized 5+7 forecast.*

PPL companies

Uncurtailed peak forecast decreases 55-77 MW consistent with lower energy forecast



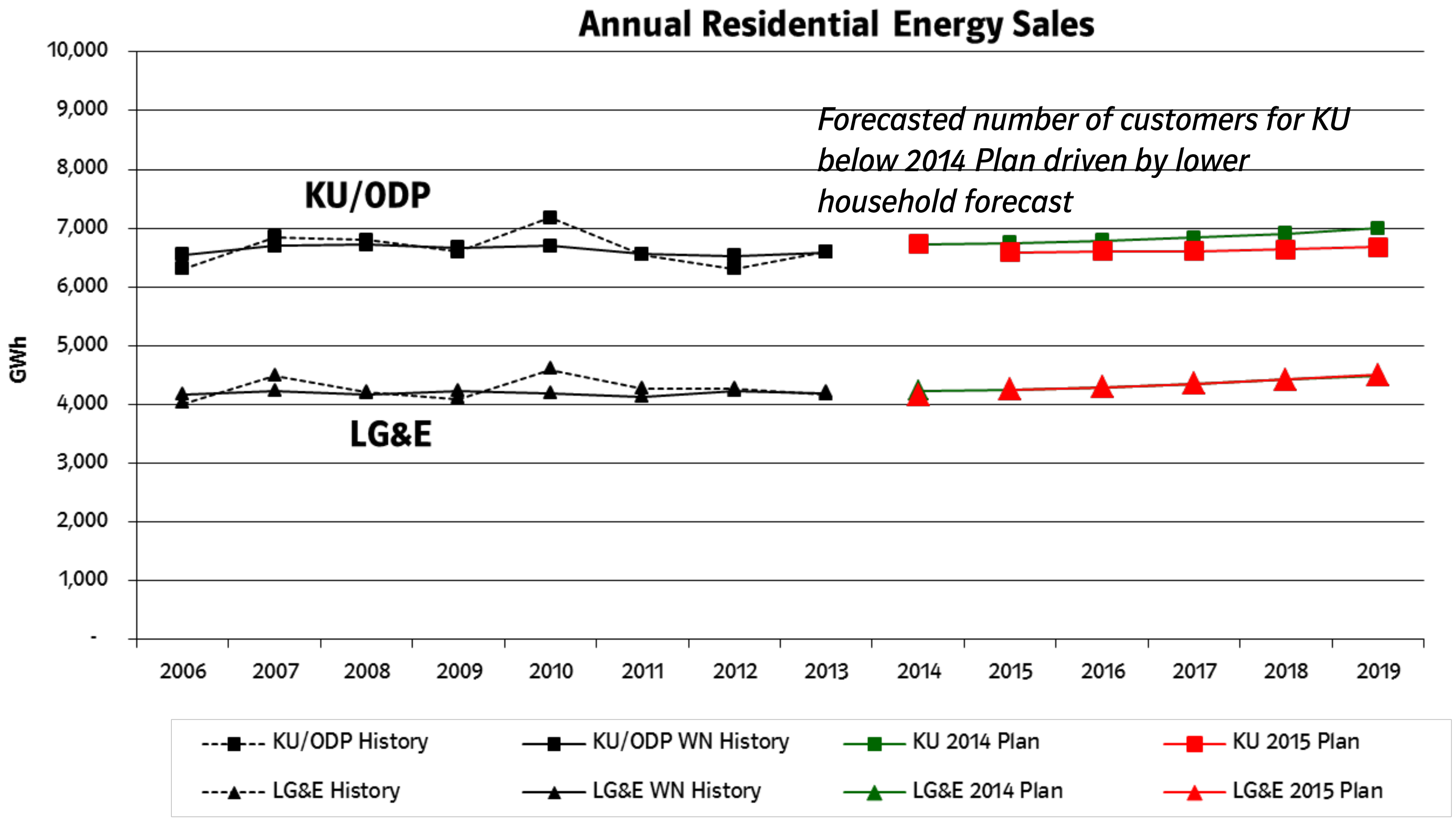
10 Municipal customers removed by 2019

[*] In 2015 Plan forecast, 2014 value is a weather-normalized 5+7 forecast.

[**] In 2015 Plan forecast, peak forecast is adjusted ~20 MW higher to cover Ft. Knox obligation.

LG&E KU
PPL companies

Residential sales forecast is slightly lower for KU



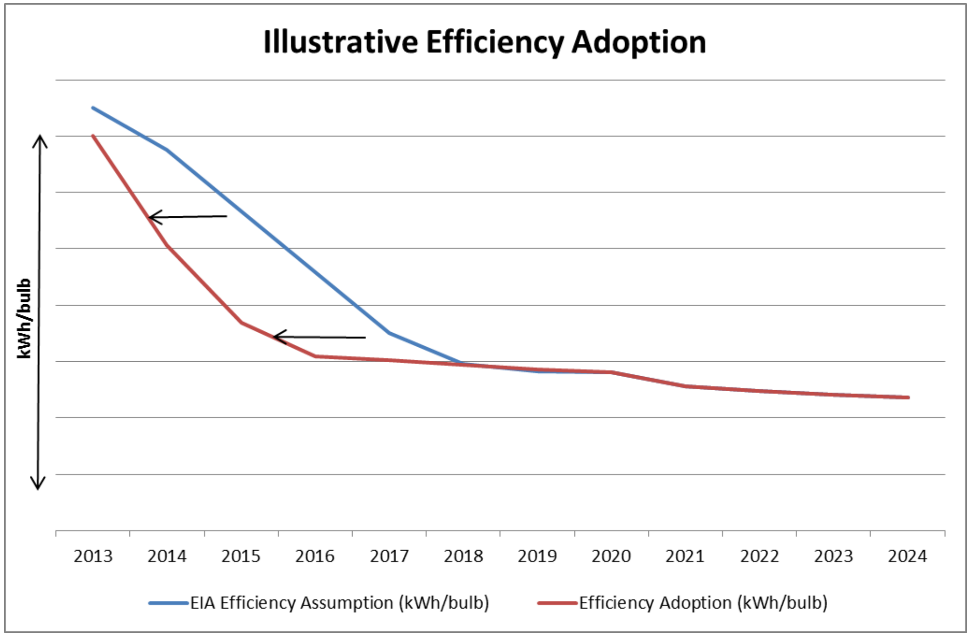
Forecasted number of customers for KU below 2014 Plan driven by lower household forecast

* *In 2015 Plan forecast, 2014 value is a weather-normalized 5+7 forecast.*

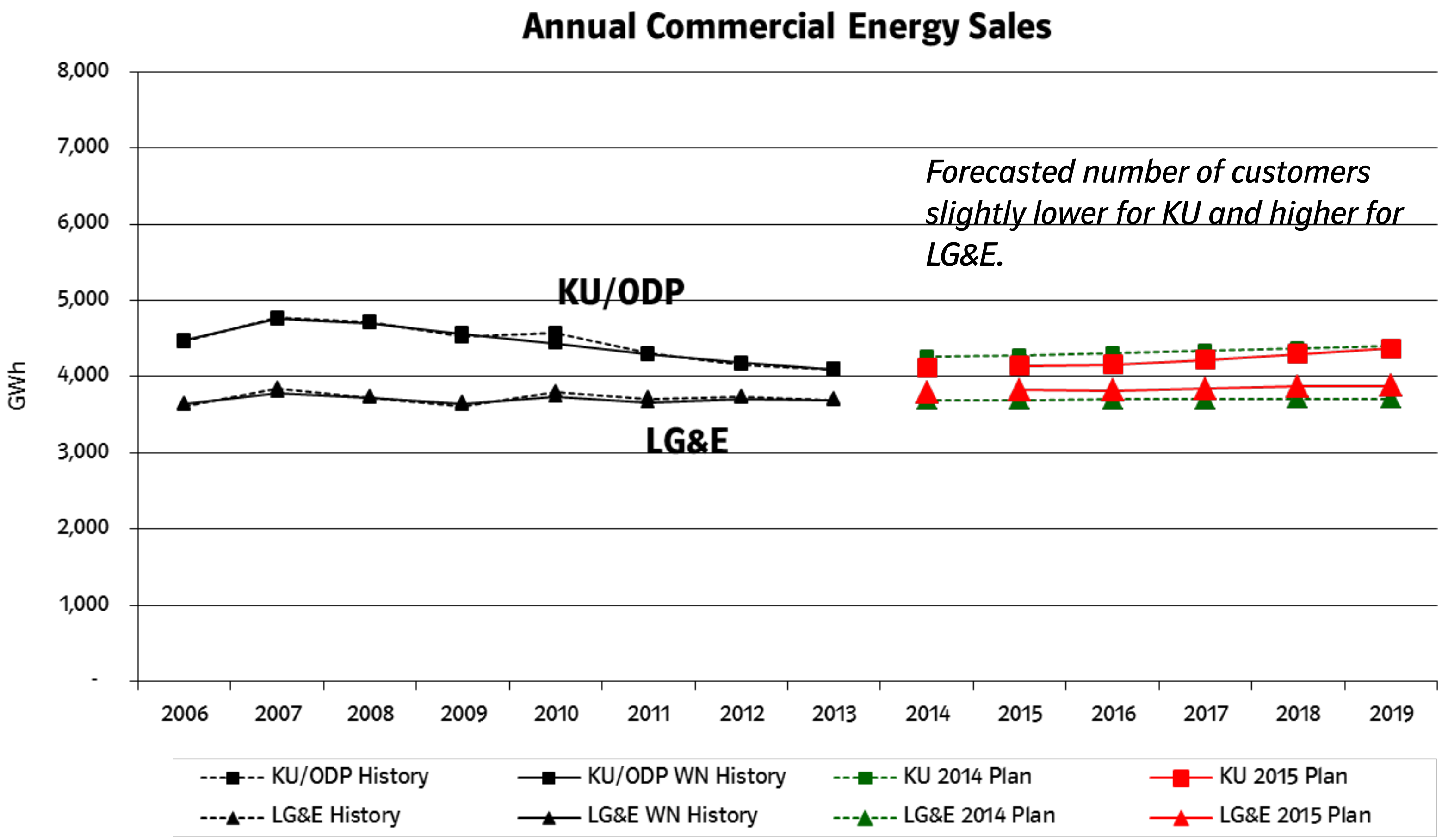
PPL companies

Residential lighting – faster adoption of LED lighting reduces residential energy consumption

- *35% of LG&E residential customers surveyed have at least one LED bulb in service*
- *Plan assumes 55% of LG&E customers add 5 additional LED bulbs each year, resulting in an average annual energy reduction of 118 GWh.*



Combined Company commercial sales largely consistent with prior plan

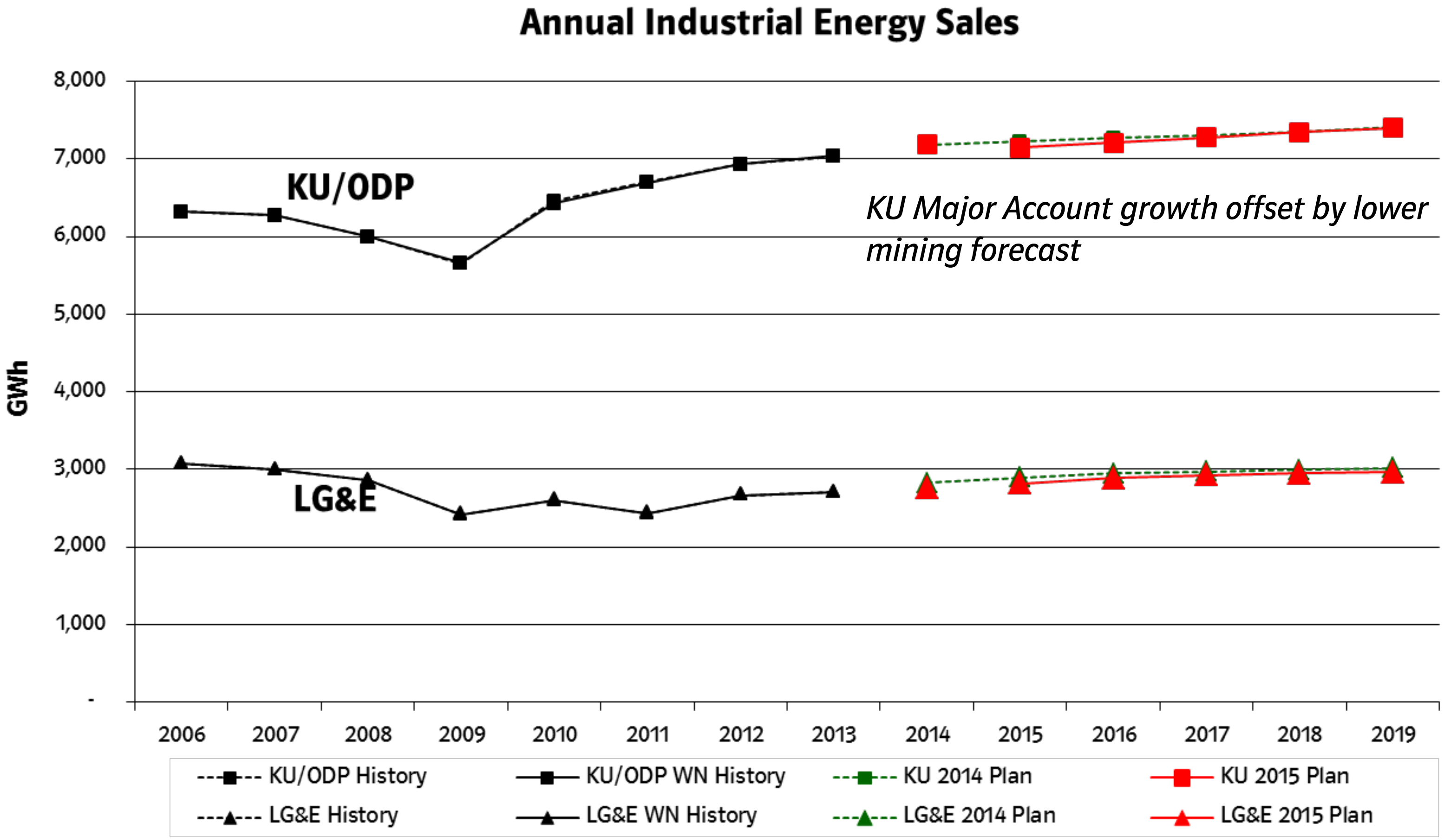


Forecasted number of customers slightly lower for KU and higher for LG&E.

** In 2015 Plan forecast, 2014 value is a weather-normalized 5+7 forecast.*

PPL companies

Slow growth expected in industrial class consistent with prior Plan

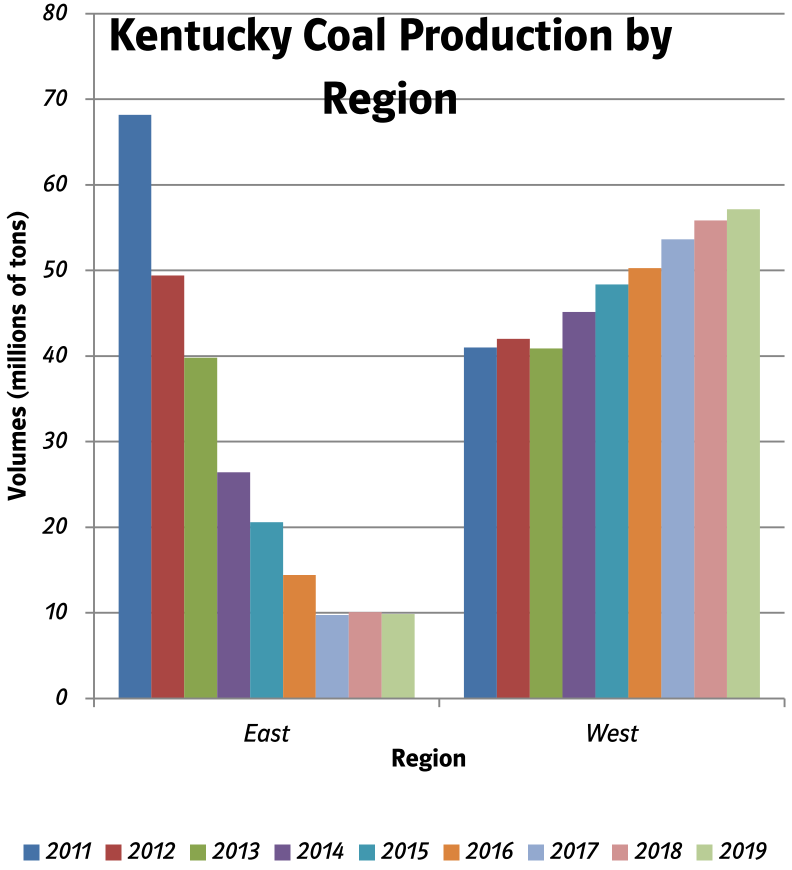


KU Major Account growth offset by lower mining forecast

* *In 2015 Plan forecast, 2014 value is a weather-normalized 5+7 forecast.*

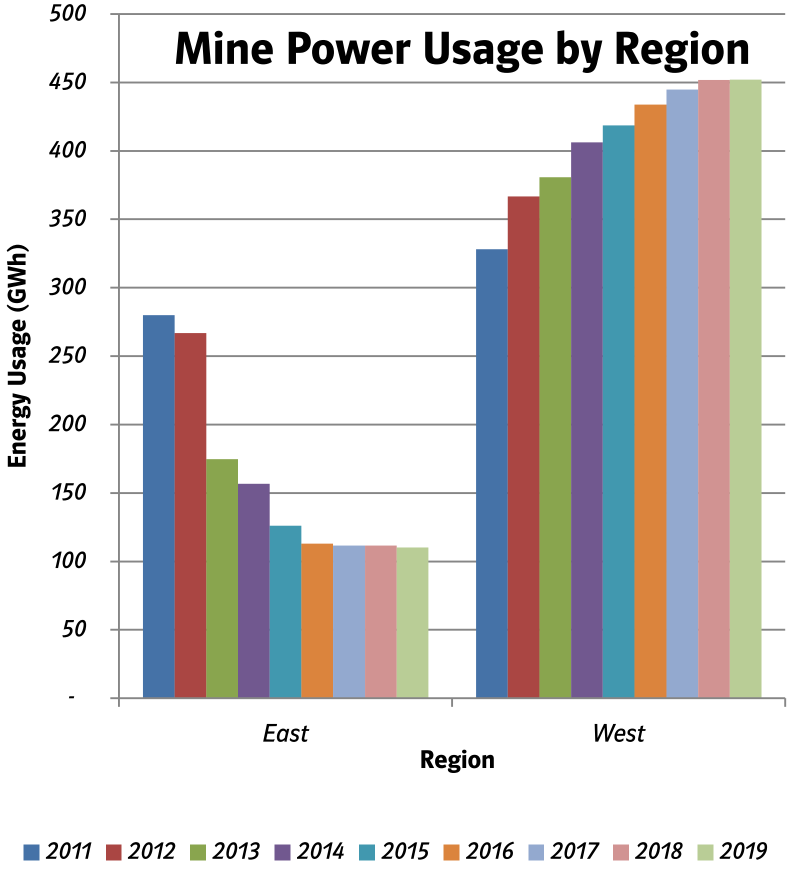
LG&E KU
PPL companies

Eastern KY coal production expected to fall by 85% from 2011 to 2019



Kentucky Coal Production by Region

Source: 2014 Spring Wood Mackenzie LTFP Forecast (updated May '14)

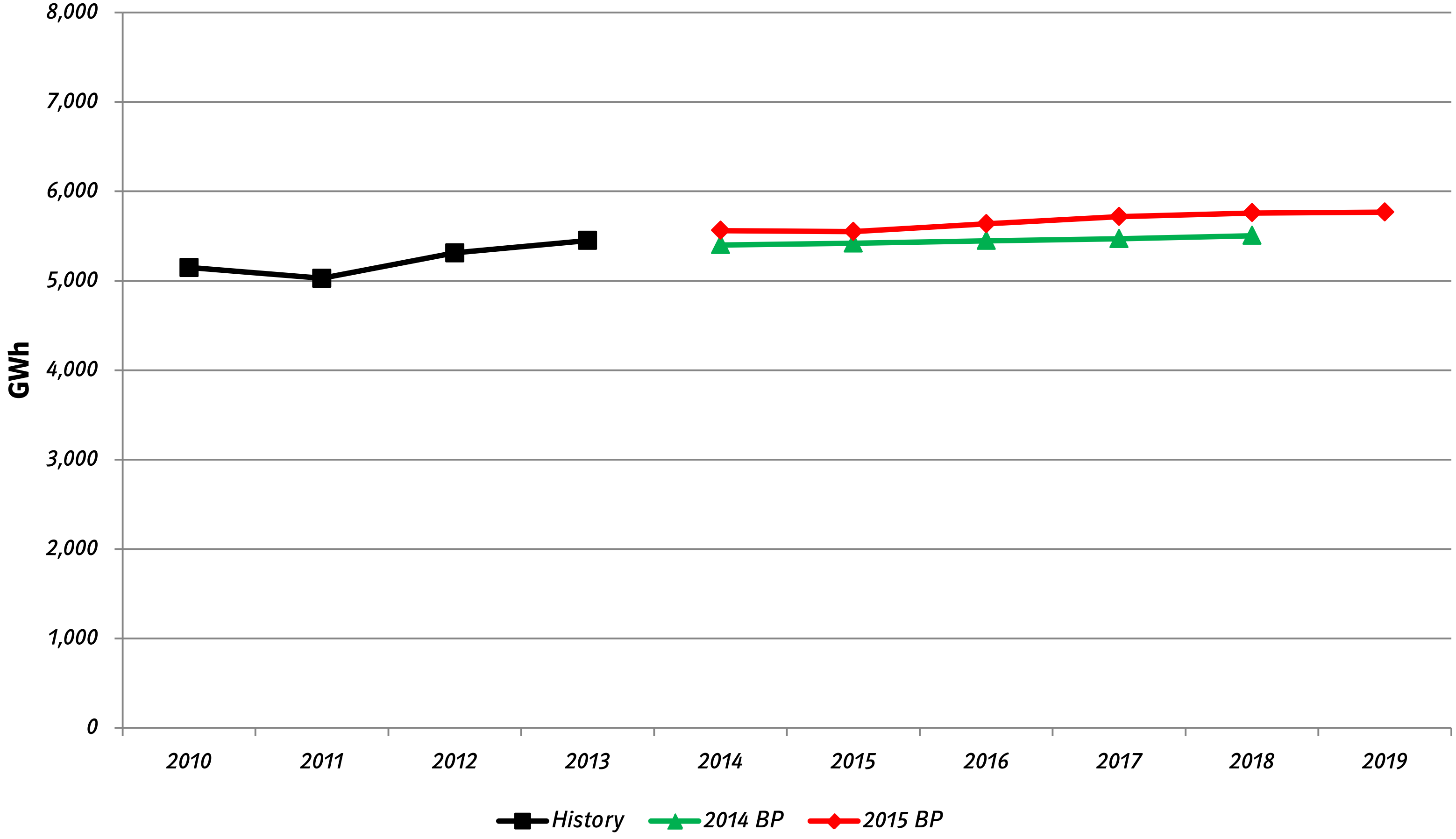


Mine Power Usage by Region

2011 – 2013 data is Billed actual. 2014 are billed actuals for Jan-May + June-Dec from 2015 BP.

PPL companies

Major Accounts History and Forecast



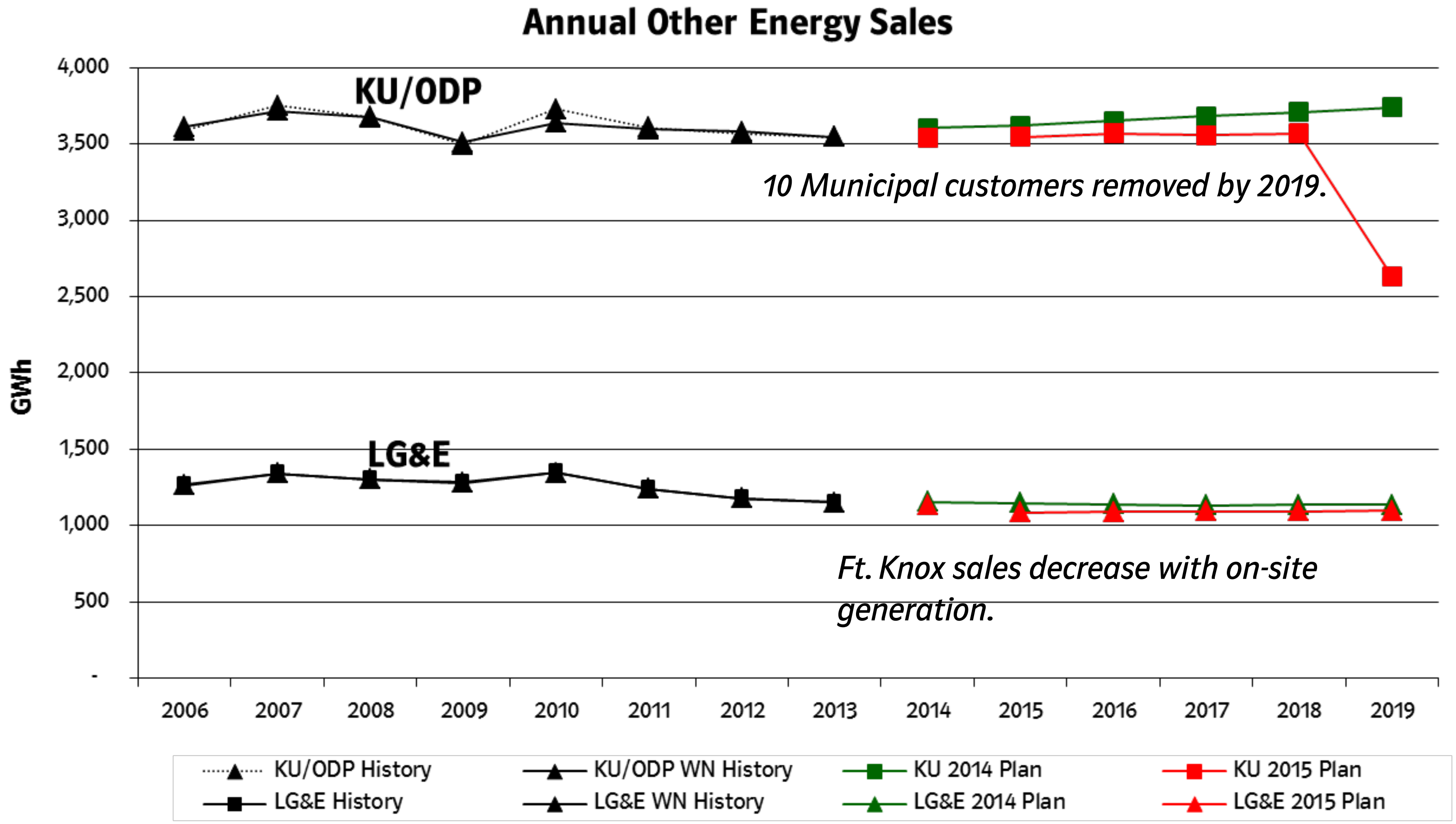
PPL companies

Changes in 26 Major Account sales for 2015: 132 GWh higher than 2014 BP

- *Significant changes for 2015*

Customer	Energy Change	Driver
North American Stainless	*62 GWh*	*Higher arc furnace load*
Carbide	*52 GWh*	*New production from an acquired plant (on peak increases from 3 MVA to 20 MVA)*
Ford - KTP	*43 GWh*	*Expansion in progress*
Lubrizol	*34 GWh*	*Expansion in progress*
Fort Knox	*(42) GWh*	*Installation of 20 MW of natural gas generation; LG&E still has obligation to serve entire load*

Public Authority sales impacted by lower Ft. Knox forecast in LG&E and lower Muni forecast in KU

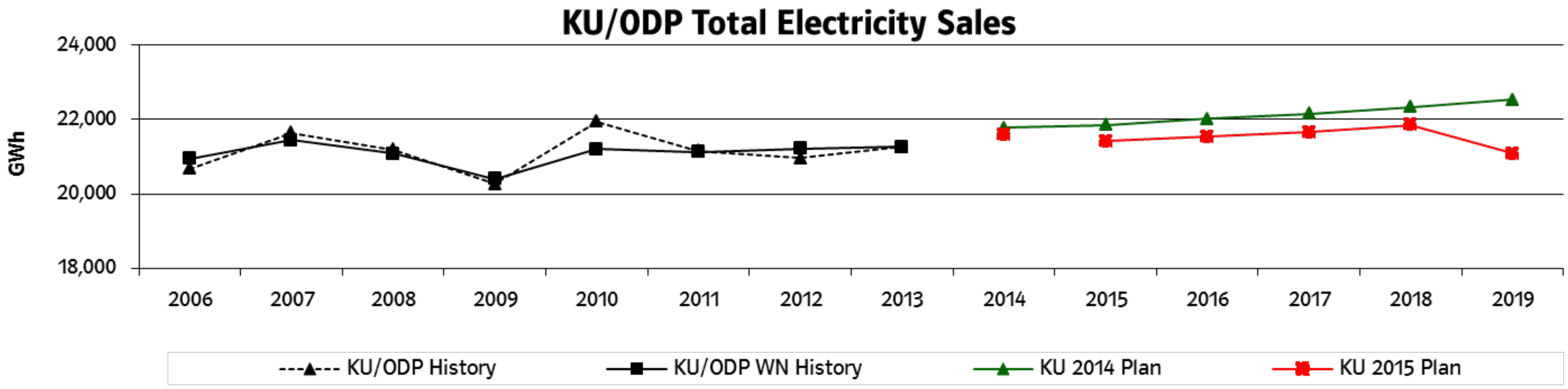


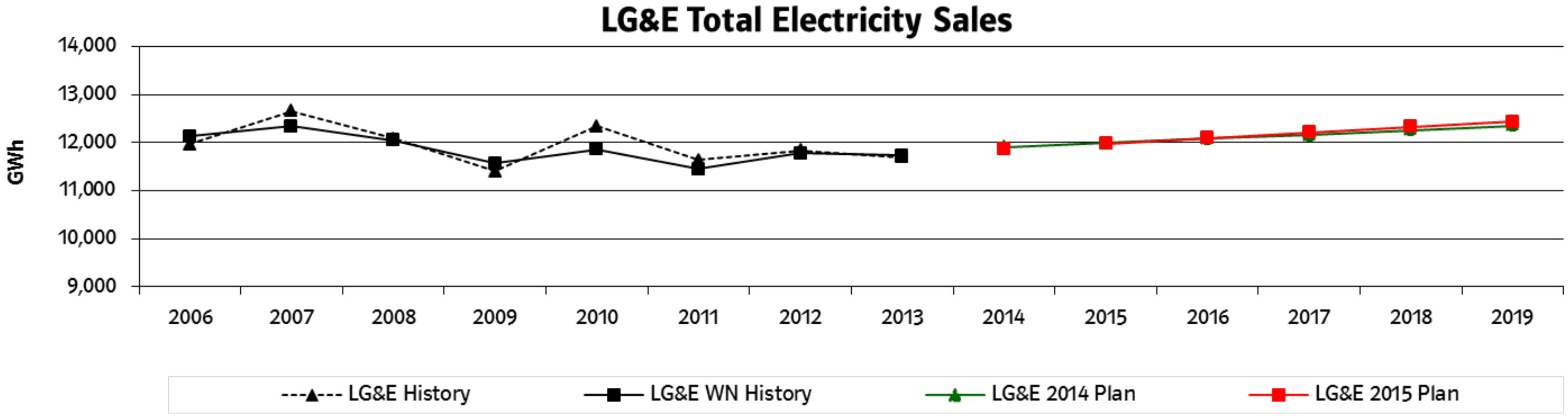
10 Municipal customers removed by 2019.

Ft. Knox sales decrease with on-site generation.

* *In 2015 Plan forecast, 2014 value is a weather-normalized 5+7 forecast.*

KU energy sales reflect lower commercial and residential usage





** In 2015 Plan forecast, 2014 value is a weather-normalized 5+7 forecast.*

2015 Plan energy forecast growth rate below EIA regional forecasts

- *2015 Plan growth rates are less than EIA regional projections*
  - *East South Central (ESC): Kentucky, Tennessee, Alabama, Mississippi*
  - *East North Central (ENC): Indiana, Illinois, Ohio, Michigan, Wisconsin*

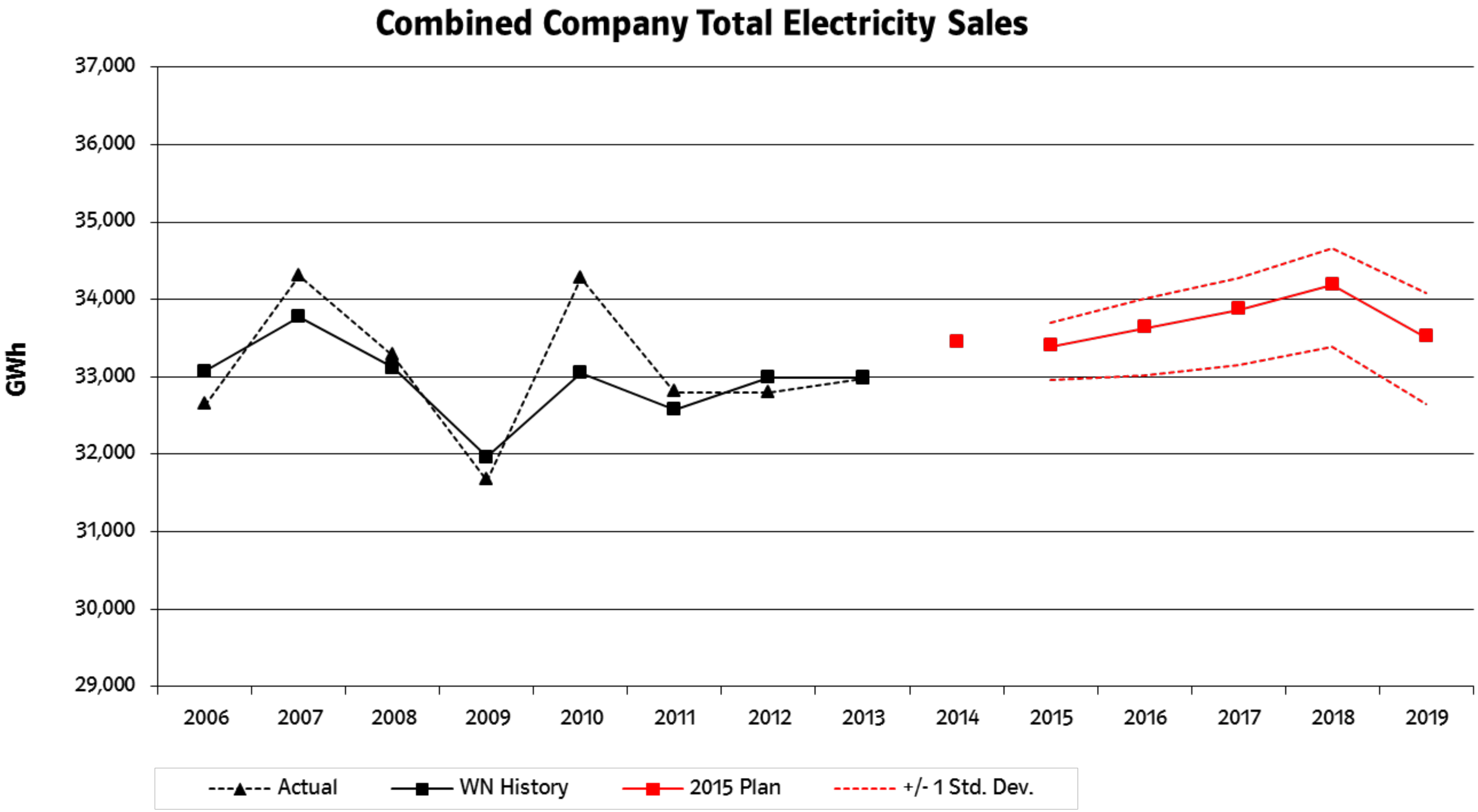
	CAGR	
	2014-2019	*2014-2040*
2015 BP (excl Munis)	*0.6%*	*0.5%*
2014 AEO ESC region	*1.9%*	*1.0%*
2014 AEO ENC region	*1.1%*	*0.6%*

PPL companies

Plan risks: weather continues to be a significant near term risk

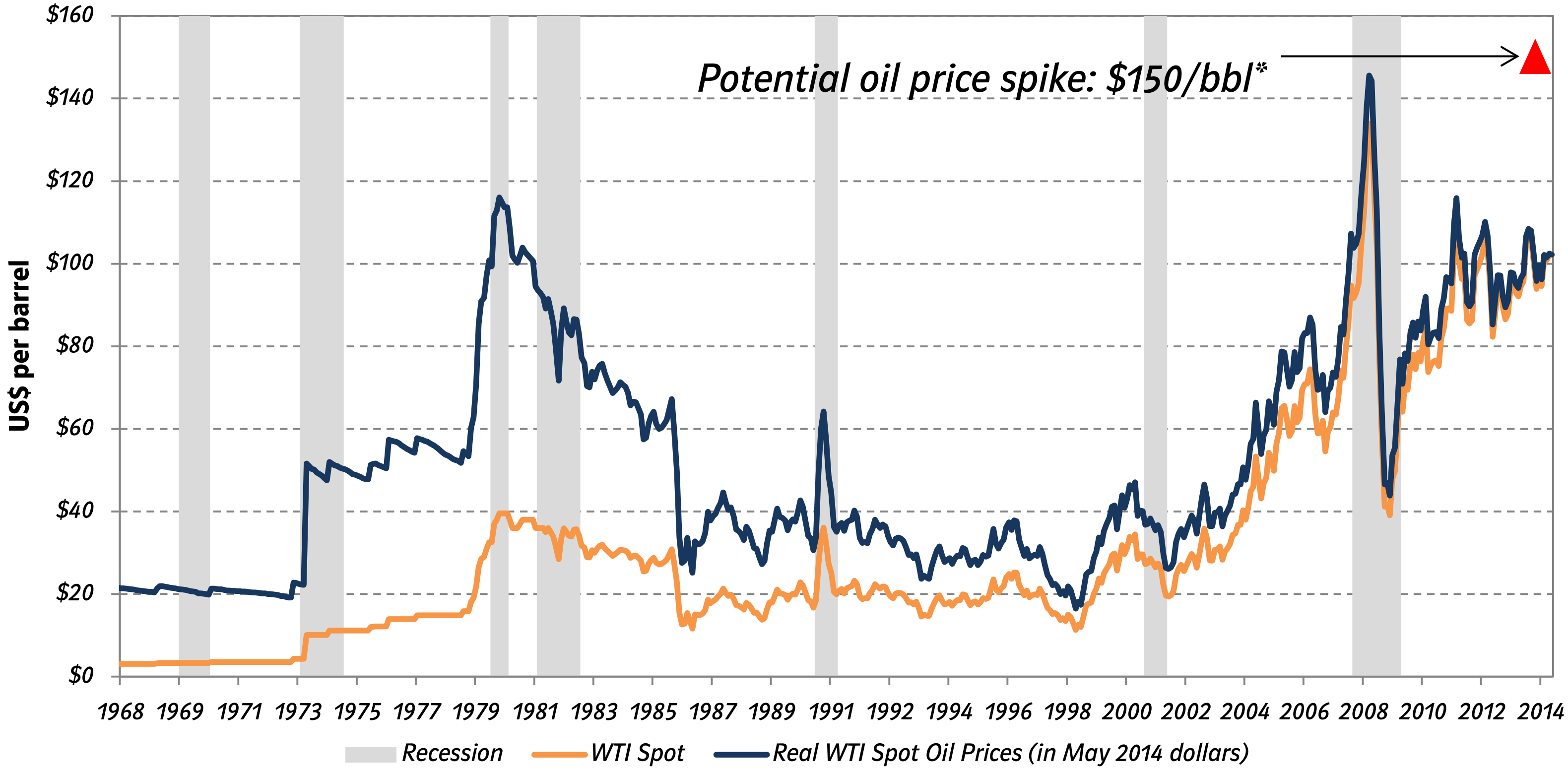
- *Near term (2015)*
  - *Weather - winter/summer extremes (+/- 400 GWh)*
  - *Economic downturn related to potential oil price spike (-500 GWh)*
- *Medium term (2015-2019)*
  - *Continued slower than forecasted economic growth (200 GWh /year; 1,000 GWh by 2019)*
  - *More rapid adoption of efficiency measures (40 GWh/year; 200 GWh by 2019)*

Sales risk based on IHS GSP risk scenario



PPL companies

Historical risk of recession with spike in oil prices



*Source: International Monetary Fund "World Economic Outlook", October 2013

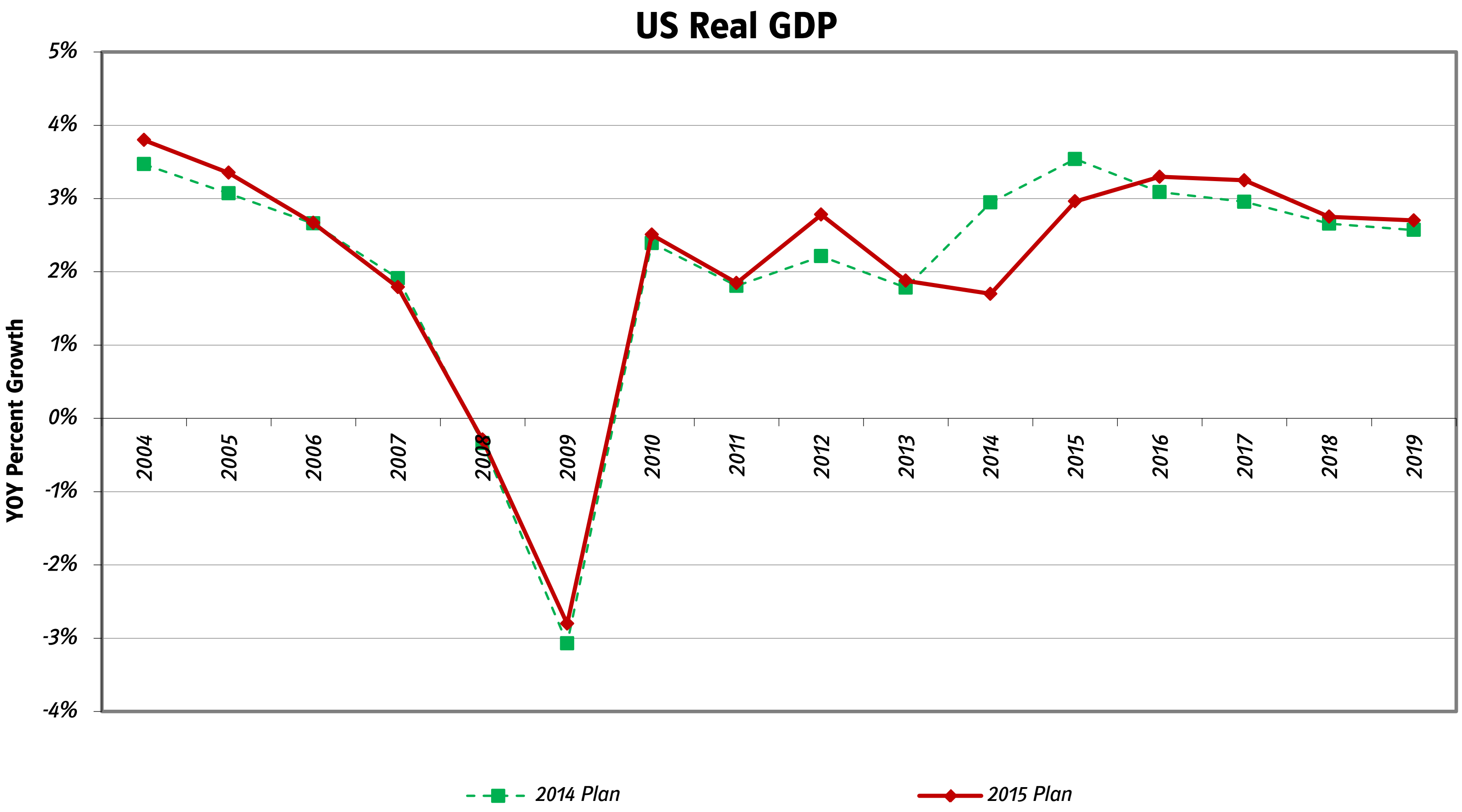
Major Account recession risk of 500 GWh based on 2008-09 downturn

Customer	2010 History (GWh)	2015 2015 BP (GWh)	Delta (GWh)
CORNING INC	75	122	47
DART CONTAINER CORP	138	185	47
DOW CORNING	195	201	6
E I DUPONT DE NEMOURS	78	90	12
FORD KTP	199	262	63
FORD LAP	91	160	69
GENERAL ELECTRIC CO	166	222	56
LUBRIZOL	87	116	29
NORTH AMERICAN STAINLESS	579	651	71
NAS Arc Furnace	472	561	88
TOYOTA MOTOR MFG KENTUCKY	383	425	42
UNITED PARCEL SERVICE	219	221	2
Total	2,682	3,215	533

PPL companies

Appendix A – Macroeconomic Inputs

Slower near-term US GDP Growth Expected



Source: IHS Global Insight

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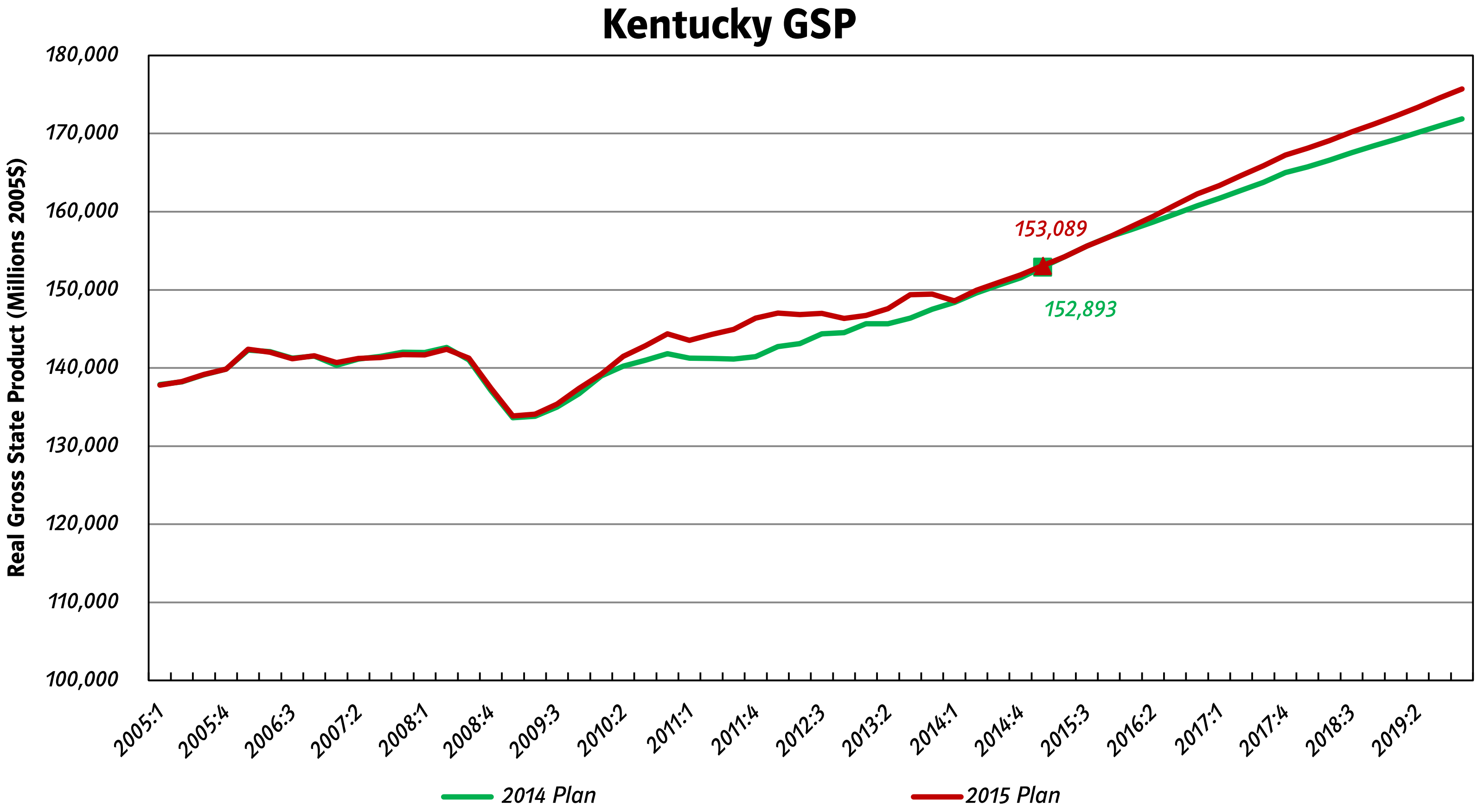
Near-term Kentucky GSP forecast unchanged



Source: IHS Global Insight

Appendix B – Customer Data

PPL companies

Customers by Rate

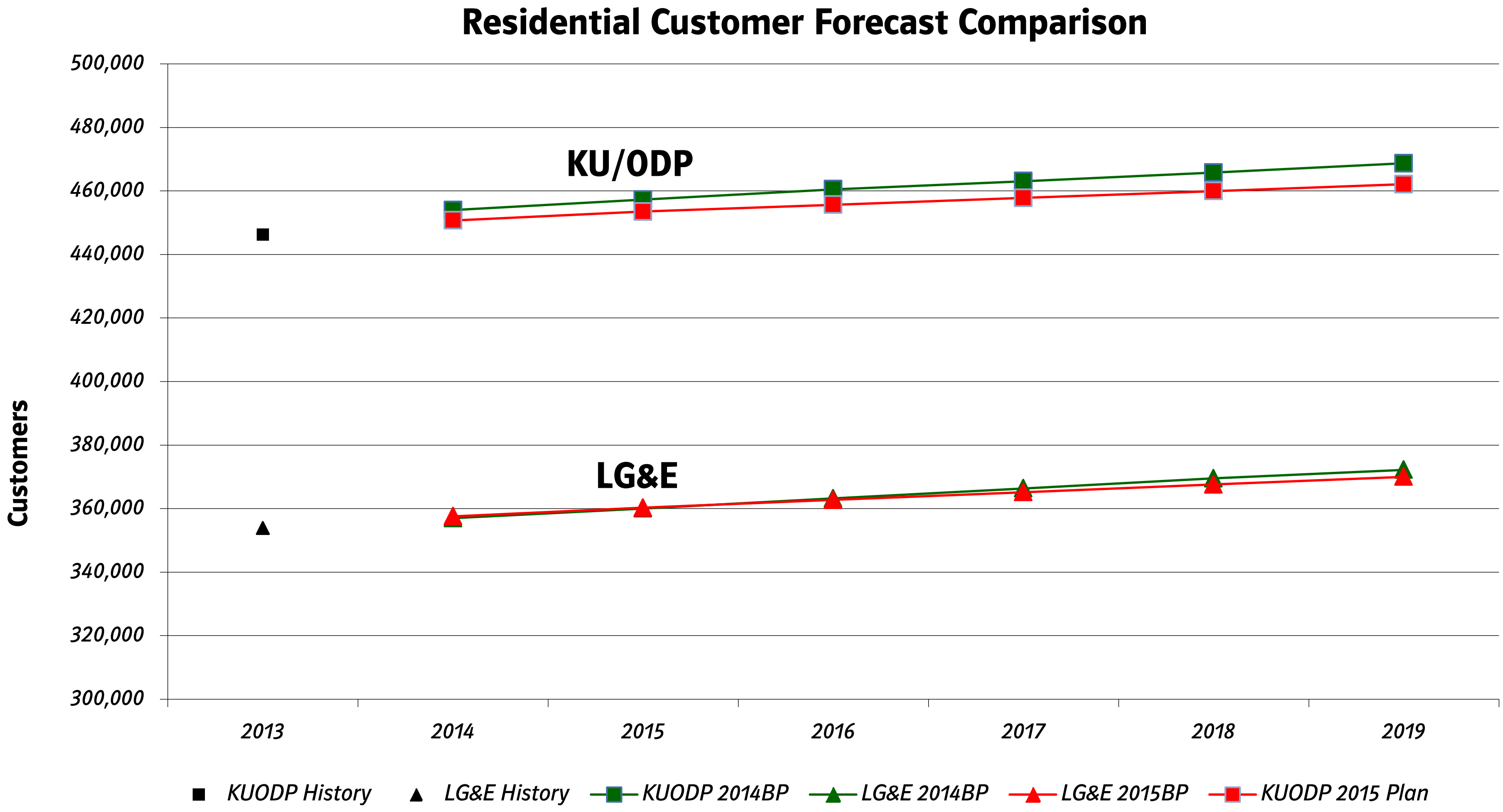
	Rate Category	Current Contract Count*	Forecast for 2015
KU/ODP	*AES*	*779*	*774*
	GS	*86,210*	*86,376*
	LTOD-Pri	*54*	*52*
	PS-Pri	*270*	*238*
	PS-Sec	*5,459*	*5,304*
	RS	*448,376*	*453,478*
	RTS	*42*	*43*
	TOD-Pri	*159*	*184*
	TOD-Sec	*422*	*416*
	FLS	*1*	*1*
	Muni Pumping	*13*	*13*
	Municipals	*12*	*12*
		541,797	*546,890*

	Rate Category	Current Contract Count*	Forecast for 2015
LG&E	*CPS-Pri*	*57*	*53*
	CPS-Sec	*2,592*	*2,580*
	CTOD-Pri	*35*	*37*
	CTOD-Sec	*202*	*214*
	GS	*44,362*	*44,497*
	IPS-Pri	*22*	*21*
	IPS-Sec	*251*	*221*
	ITOD-Pri	*66*	*68*
	ITOD-Sec	*74*	*90*
	RS	*356,308*	*360,289*
	RTS	*12*	*12*
		403,979	*408,080*

**Average of Jan-May 2014*

PPL companies

KU Residential customer growth slightly below 2014 Plan



Residential Customer Forecast Comparison

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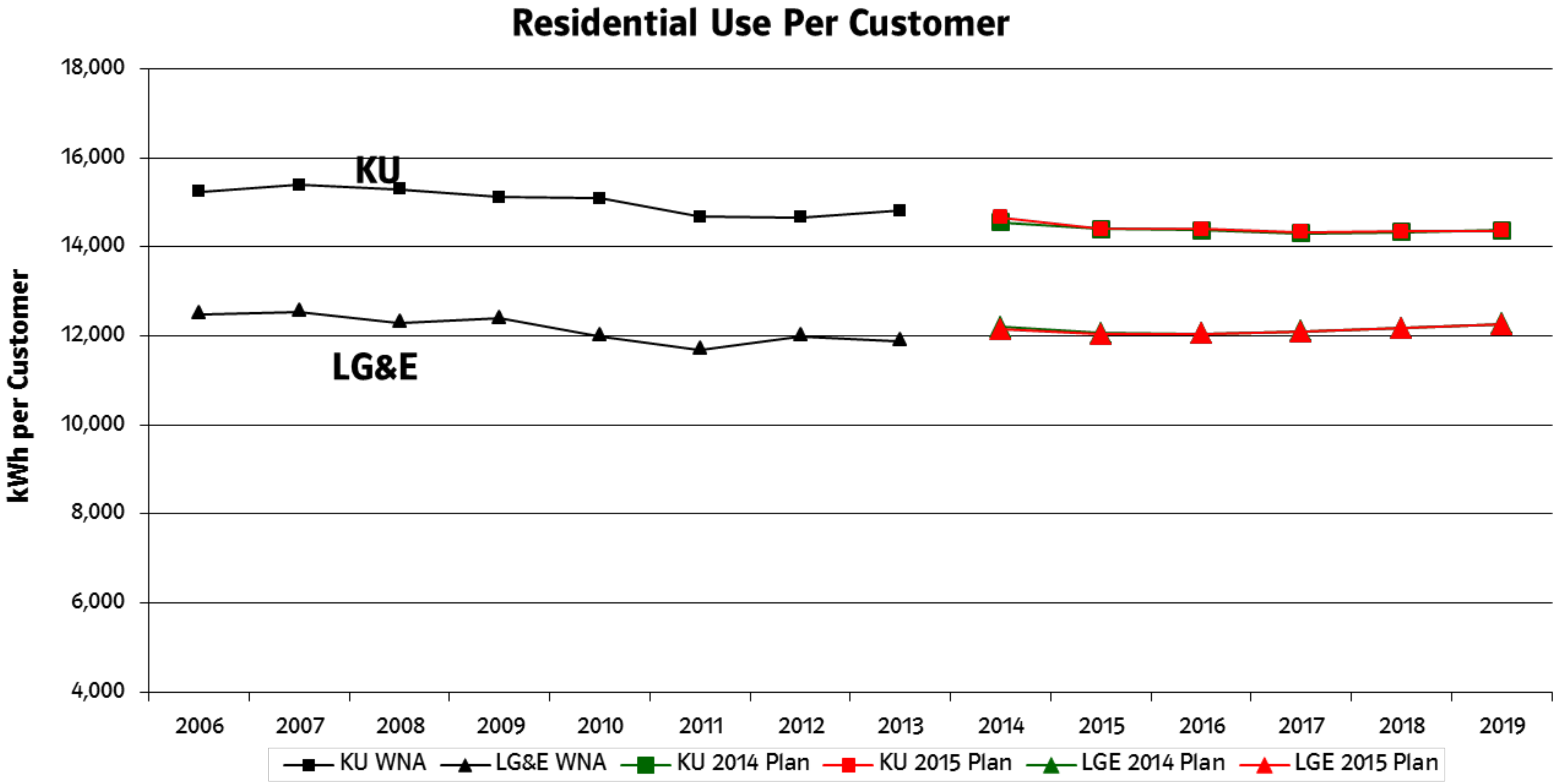
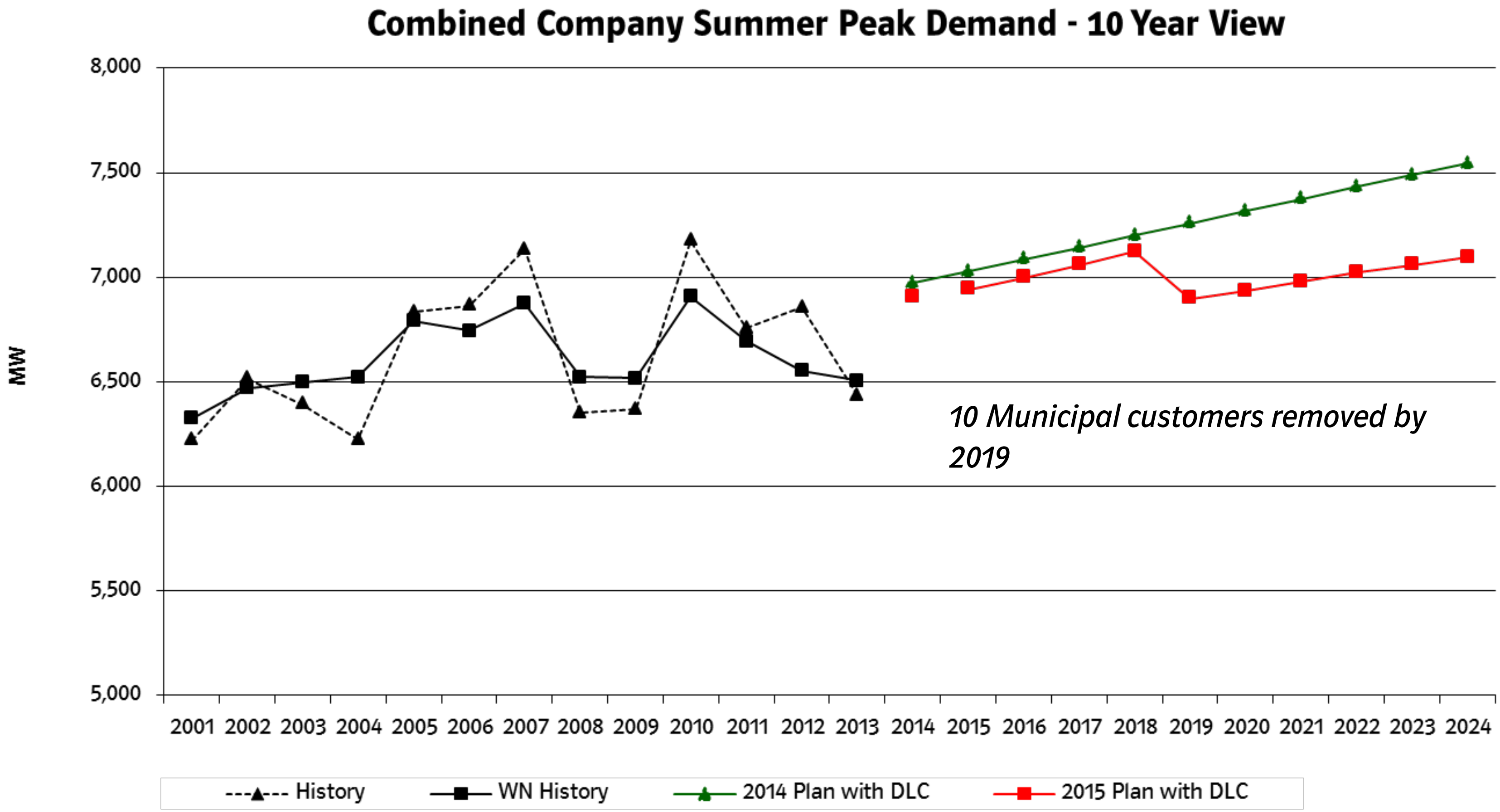
Use per customer for both KU and LG&E largely consistent with 2014 Plan



** In 2015 Plan forecast, 2014 value is a weather-normalized 5+7 forecast.*

Uncurtailed peak forecast after DLC slightly lower consistent with lower energy forecast and higher DLC customer forecast

Combined Company Summer Peak Demand - 10 Year View



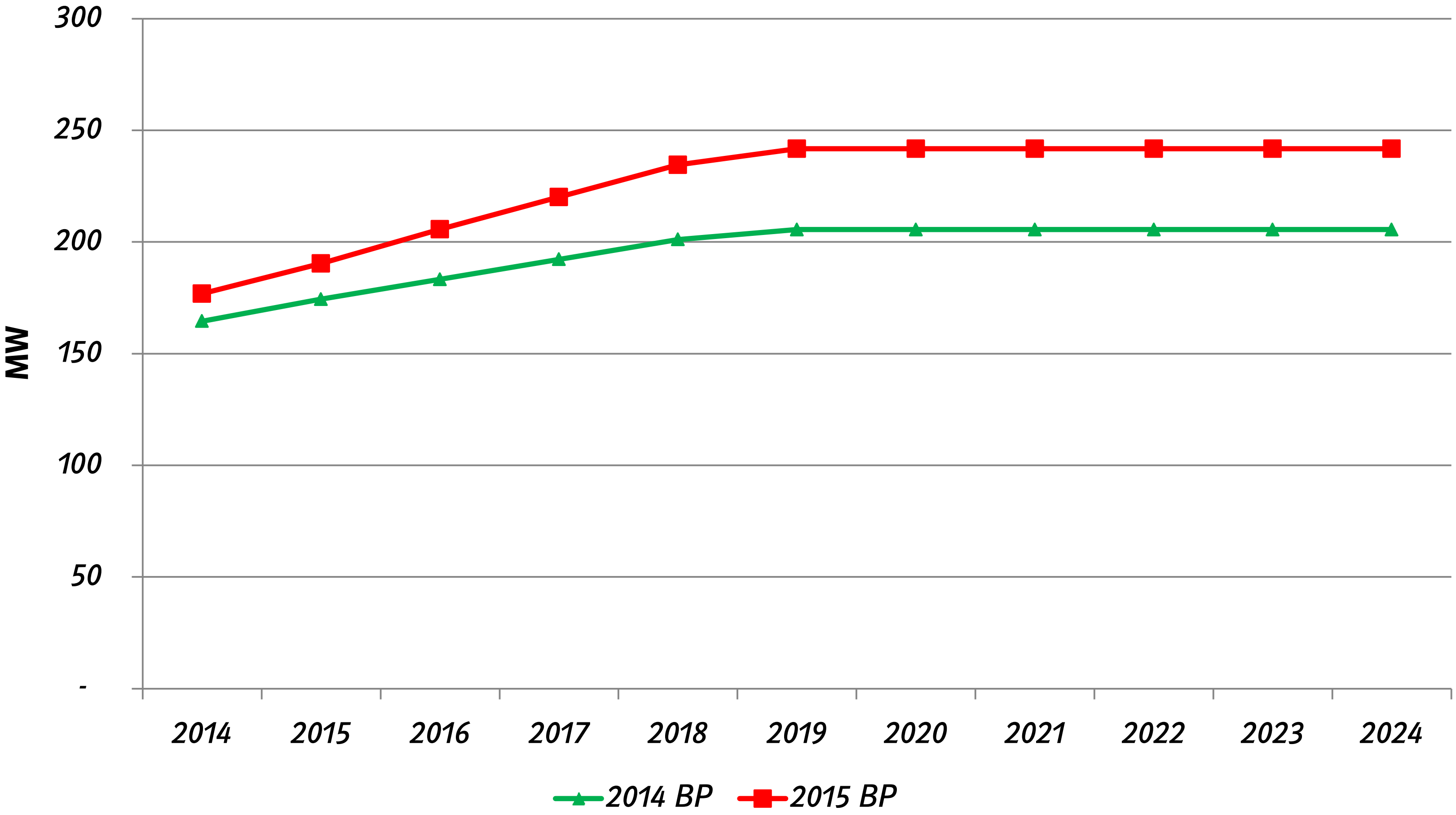
10 Municipal customers removed by 2019

** In 2015 Plan forecast, 2014 value is a weather-normalized 5+7 forecast.*

*** In 2015 Plan forecast, peak forecast is adjusted ~20 MW higher to cover Ft. Knox obligation.*

LG&E KU
PPL companies

Additional DLC of 36 MW by 2019 due to higher customer participation forecast



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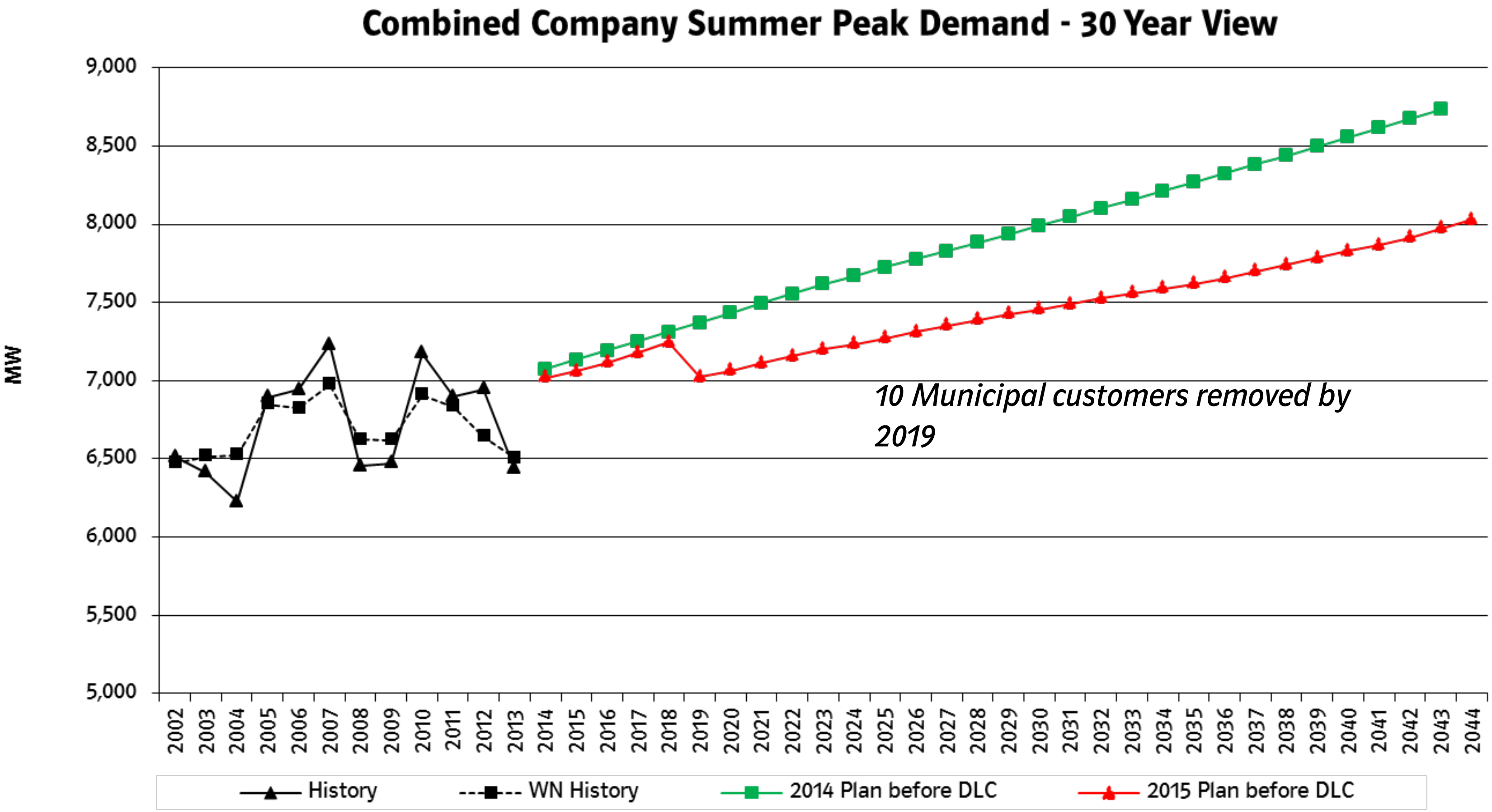
Uncurtailed peak forecast slightly lower consistent with lower energy forecast and reduction in municipal load



10 Municipal customers removed by 2019

** In 2015 Plan forecast, 2014 value is a weather-normalized 5+7 forecast.*

*** In 2015 Plan forecast, peak forecast is adjusted ~20 MW higher to cover Ft. Knox obligation.*

PPL companies

Annual Natural Gas Volume Forecast Process

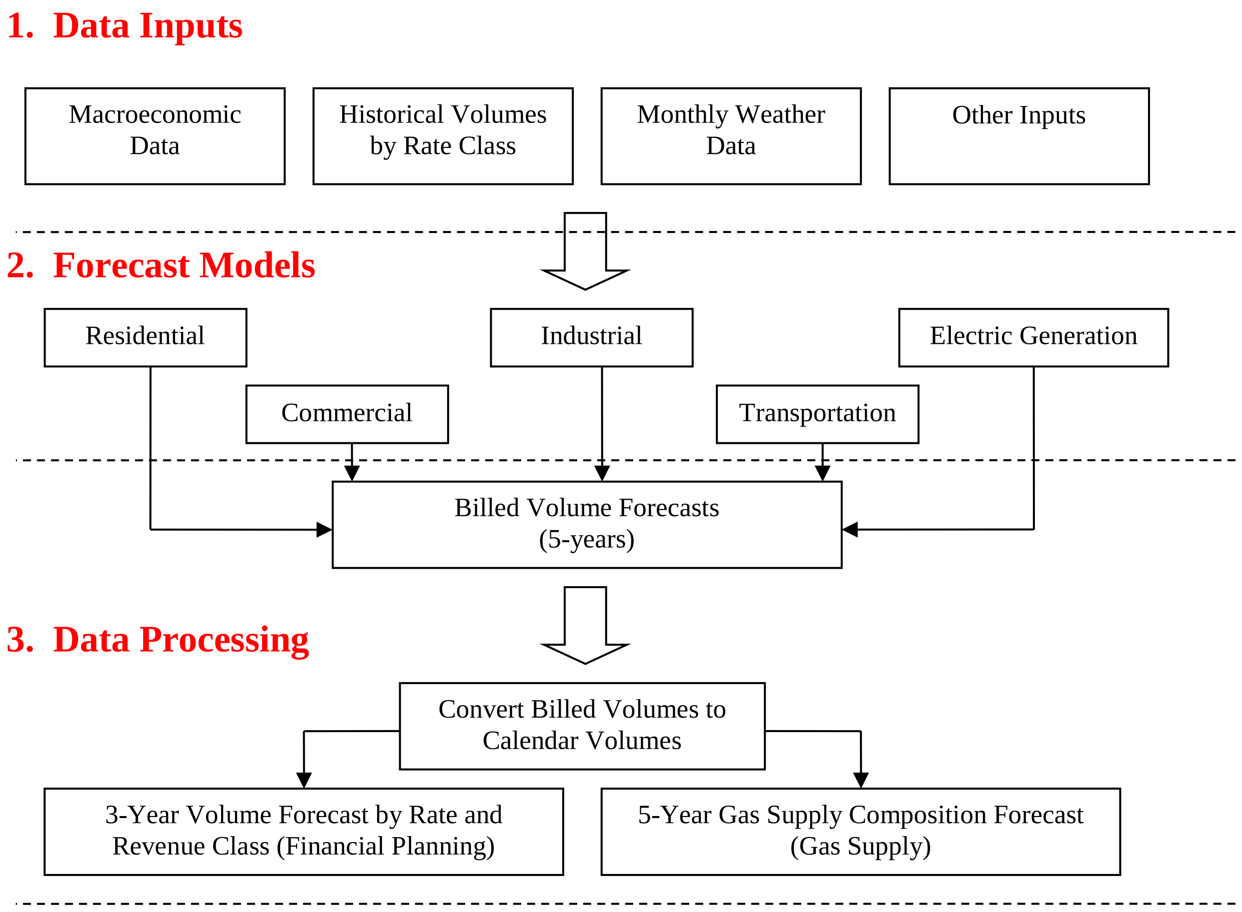
Sales Analysis & Forecasting
September 2014

Table of Contents

1 Introduction

The Sales Analysis & Forecasting groupannually develops the natural gas sales and transportation forecasts for the Louisville Gas & Electric Company (LG&E). LG&E natural gas customers can broadly be classified as either sales customers or transportation customers. Furthermore, sales customers can be further divided into firm and interruptible customers. LG&E must procure gas for firm sales customers, but it has no obligation to procure gas for interruptible (AAGS) sales customers. Sales customers are grouped by residential, industrial, and commercial gas service rates. Transportation customers are large industrial and commercial customers on LG&E's distribution system who contract for their own gas supply and use the company's pipeline system to deliver gas from an interstate pipeline connection point with LG&E to their facility. These forecasts are an input to the company's revenue and gas supply expense forecast. This document describes the processes used to produce the annual volume forecasts. The forecast process can be divided into three parts (see Figure 1).

Figure 1 – Natural Gas Volume Forecast 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 gas sales and customer data

- Weather data (30-year normal degree-day series)
- Other data, including billing cycle forecasts and residential heating appliance shares and efficiencies.

The input data is used to specify various forecast models. LG&E's natural gas volumes are forecasted by rate class as each model is used to forecast sales for a group of customers with homogeneous usage patterns within the same, or similar, tariff rates.

Most of the forecast models produce volume forecasts on a monthly billed basis.[1] In the third part of the forecast process, gas volume data from the forecast models is processed to meet the needs of the forecast end users. The monthly billed energy forecasts must first be converted to calendar month (or "as-used") forecasts. The billed and calendar sales forecasts are allocated by rate and revenue class for the Financial Planning department.[2]

The final part of the forecast process includes validating and documenting the forecast results. To ensure the 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 is discussed in more detail in the following sections.

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[1] All customers are assigned to one of 20 billing cycles. A billing cycle determines what time of the month a customer's meter is read. Because most billing cycles do not coincide precisely with the boundaries 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. See Appendix C

2 Input Data

Table 1 provides a summary of the data inputs. The sections that follow describe key processes used to prepare the data for use in the forecast process.

Table 1 – Volume Forecast Data Inputs

Data	***Source***	***Format***
State Macroeconomic Data (Employment, Wages)	IHS Global Insight	Annual or Quarterly by County – History and Forecast
State Demographic Data (Households, Personal Income, Population)	Global Insight & Kentucky Data Center	Annual or Quarterly – History and Forecast
National Macroeconomic Data (Industrial Production Index)	Global Insight	Annual or Quarterly – History and Forecast
Weather	NOAA's National Climatic Data Center (NCDC)	Daily HDD/CDD by Weather Station – History
Historical Gas Supply Cost	State Regulation and Rates	Monthly
Henry Hub Gas Price Forecast	Corporate Long-term Planning Process	Monthly
Gas Supply Cost Forecast	Gas Supply (based on Henry Hub Gas Price Forecast)	Monthly
Historical Billing Cycle Meter Reading Schedule	Revenue Accounting	Billing Cycle Read Dates
Heating Appliance Efficiencies	US Energy Information Administration (EIA)	Annual Efficiencies by Appliance (Furnace, Water Heater)
Residential End-Use Data	EIA, LG&E Residential End-Use Survey	Appliance Saturations
Commercial End-Use Data	EIA, LG&E Commercial End-Use Survey	Appliance Saturations
Billed Sales History by Rate Class	CCS Billing System	Monthly
Number of Customers History by Rate Class	CCS Billing System	Monthly
Individual Customer Usage History	CCS Billing System	Monthly
Forecasts of Gas Used by Electric Generation	Generation Planning	Monthly

2.1 Service Area-Specific Macroeconomic Forecasts

LG&E's natural gas service area includes all or portions of 17 Kentucky counties.[3] Global Insight produces forecasts of macroeconomic drivers by county and industry. Service area-

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[3] LG&E is the only gas utility serving Bullitt, Henry, Larue, Meade, Nelson, Oldham, Spencer and Trimble counties. LG&E also serves parts of Barren, Green, Hardin, Hart, Jefferson, Marion, Metcalfe, Shelby and Washington counties.

specific macroeconomic forecasts are created by aggregating the county-specific forecasts for the counties in LG&E's service area.

2.2 Software Tools

The following software packages are used in the forecast process:

- Microsoft Office: Excel, PowerPoint, Access
- SAS
- Itron Metrix ND

2.3 Billed Usage History

Historical billed usage volumes for all retail customers are taken from the LG&E Customer Care System (CCS). The LG&E Billed Transport Report contains historical usage volumes for all transportation customers. Transportation customers nominate – on a daily basis – the amount of gas they expect to consume. A daily or monthly "imbalance" is computed as the difference between the amount of natural gas actually consumed and the amount of natural gas nominated.

For several classes, a significant portion of the total gas usage is made up of gas consumed by heating appliances (e.g., gas furnaces and gas water heaters). Heating appliance usage is a function of appliance efficiencies and the weather. As appliance efficiencies improve over time, the average use-per-customer – for a given class and temperature – will decline in the absence of customers' behavioral changes.

The heating appliances that consume the most natural gas are the gas furnace and gas water heater. Total usage and efficiency data for these appliances are provided by the US Energy Information Administration (EIA) and are used as inputs into some of the forecast models.

2.4 Processing of Weather Data

Weather is a key explanatory variable in the gas forecast models. The weather dataset from the National Oceanic & Atmospheric Administration's (NOAA) National Climatic Data Center (NCDC) contains temperatures (maximum, minimum, and average), heating degree days (HDD), and cooling degree days (CDD) for each day and weather station over the past 30 years. This data and the Company's meter reading schedule are used to create (a) a historical weather series by billing month and (b) a forecast of "normal" weather by billing month.[4] Each of these processes is summarized below.

2.4.1 Historical Weather by Billing Month

The methodology 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 cycle.[5] Each historical billing month consists of 20 cycles. The Company's

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[4] "Normal" weather is be defined as the average weather over a historical period. The Companies do not attempt to forecast any trends in weather.

[5] Weather data in the gas forecast is taken from the weather station at Standiford Field Airport (SDF) in Louisville.

historical meter reading schedule contains the beginning and ending date for each billing cycle.

2. Average the billing cycle total HDDs and CDDs by billing month.

2.4.2 Normal Weather Forecast by Billing Month

The methodology used to produce the forecast of normal weather by billing month includes the production of a daily forecast of normal weather. The methodology used to develop the daily forecast (summarized in Steps 2-5) is consistent with the methodology 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 monthly weather by *calendar* month by averaging the monthly degree-day values and over the period of history upon which the normal forecast is based. The normal weather forecast is based on the most recent 30-year historical period. Therefore, the normal HDD value for January is the average of the 30 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 30 January 1 temperatures in the historical period. This process excludes February 29.
3. Smooth the daily values using a 30-day moving average centered about 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 Company's forecasted meter reading schedule contains the beginning and ending date for each billing cycle through the end of the forecast period. In this step, sum the HDD and CDD values by billing cycle. Use the February 28 weather data as a proxy for February 29 when billing cycles include leap days.
6. Average the billing cycle totals by billing month.

2.5 Forecasts of Gas Used by Electric Generation

Effective May 1, 2008, LG&E and KU's electric generation business entered into a special contract ("Electric Generation Special Contract") with LG&E's gas distribution business for gas sales and transportation services. Under the contract, the Cane Run and Mill Creek generating

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[6] The NCDC derives daily normal values by applying a cubic spline to a specially prepared series of the monthly normal values.

stations are served as a firm sales customer and the Paddy's Run generating station is served as a transportation customer. As of September 2014, Cane Run will take gas directly from Texas Gas at a new interconnection point built for the Cane Run natural gas combined cycle plant and will no longer be served by the LG&E Gas Business.

The forecasts of gas used by each of the aforementioned generating stations are provided by the Generation Planning group. In addition, the Generation Planning group provides a forecast of gas used by the Zorn generating station, which is also served via the LG&E gas distribution system (but not as a part of the Electric Generation Special Contract).

From a revenue accounting perspective, the gas consumed by the Cane Run and Mill Creek stations is accounted for in a separate Interdepartmental Sales revenue class. The gas consumed by the Paddy's Run station is accounted for in the Interdepartmental Transport revenue class. The gas consumed by the Zorn station is considered Company Use and is recorded in the utility financial reports as part of gas 'Used in Electric Generation.'

3 Forecast Models

LG&E natural gas customers can broadly be classified as either sales customers or transportation customers. Sales customers include customers on the residential, industrial, and commercial gas service rates. Transportation customers are large industrial and commercial customers on LG&E's distribution system who contract for their own gas supply. Each forecast is discussed in detail in the following sections.

3.1 Residential Forecast

The residential forecast consists of all customers on the Residential Gas Service (RGS) rate schedule. The RGS class accounts for approximately half of the total volume forecast. RGS sales are forecasted as the product of a customer forecast and a use-per-customer forecast.

3.1.1 Residential Gas Service (RGS) Customer Forecast

The RGS customer forecast is modeled as a function of the number of forecasted households in the LG&E service territory. Household and population data by county and Metropolitan Statistical Area (MSA) is available from IHS Global Insight and the Kentucky Data Center.

3.1.2 Residential Gas Service (RGS) Use-per-Customer Forecast

The RGS use-per-customer forecast is developed using a Statistically-Adjusted End-Use (SAE) model (similar to what is used to forecast residential electric sales). Such a model combines an econometric model – that relates monthly sales to various explanatory variables such as weather and economic conditions – with traditional end-use modeling. For natural gas, the SAE approach defines energy use as a function of energy used by heating equipment and other natural-gas fueled equipment.

$$\text{Use-per-Customer} = a_1 * \text{XHeat} + a_2 * \text{XOther} + \sum_i \alpha_i X_i$$

The heating and other components (the X variables) are based on various input variables including weather (heating and cooling degree days), appliance saturations, efficiencies, and economic and demographic variables such as income, population, members per household and the gas supply cost. In addition, certain binary variables may be added to compensate for anomalies in the data or other events. 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 discussion of each of these components and the methodology used to develop them is contained in Appendix A.

3.2 Commercial Forecast

The commercial forecast is comprised of customers on the Firm Commercial Gas Service (CGS) and Commercial As-Available Gas Service (CAAGS) rate schedules. Given the unique characteristics of these classes, each class is modeled separately. CGS volumes are forecasted as the product of a customer forecast and a use-per-customer forecast.

3.2.1 Firm Commercial Gas Service (CGS) Customer Forecast

The CGS customer forecast is modeled based on its own historical trend independent of the number of RGS customers.

3.2.2 Firm Commercial Gas Service (CGS) Use-per-Customer Forecast

Similar to the RGS use-per-customer forecast, the CGS volume forecast is developed using an SAE model. Such a model combines an econometric model – that relates monthly sales to various explanatory variables such as weather and economic conditions – 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.

$$\text{Use-per-Customer} = a1*XHeat + a2*XOther$$

The heating and other components (the X variables) are based on various input variables including weather (heating and cooling degree days), appliance saturations, efficiencies, and economic and demographic variables such as income, population, members per household and the gas supply cost. Once the historical profile of these explanatory variables is established, a regression model is specified to identify the statistical relationship between changes in these variables and changes in the dependent variable (volumes). A discussion of each of these components and the methodology used to develop them is contained in Appendix B.

3.2.3 Commercial As-Available Gas Service (CAAGS) Forecast

CAAGS sales are forecasted as a portion of total As-Available gas sales. The forecast of CAAGS volumes is modeled as a function of weather, natural gas prices and number of customers.

3.3 Industrial Forecast

The industrial revenue class is comprised of customers on the Firm Industrial Gas Service (IGS) and Industrial As-Available Gas Service (IAAGS) rate schedules.

3.3.1 Firm Industrial Gas Service (IGS) Forecast

IGS volumes are forecasted in total as a function of natural gas prices, number of customers and a rate-specific industrial production index.

3.3.2 Industrial As-Available Gas Service (IAAGS) Forecast

IAAGS sales are forecasted as a portion of total As-Available gas sales. The forecast of IAAGS volumes are modeled as a function of weather, natural gas prices and number of customers.

3.4 Interdepartmental Sales Forecast

The interdepartmental sales forecasts consist of gas used by the Cane Run and Mill Creek generating stations. The forecast of gas used by these stations is made based on usage over the last twelve months in conjunction with the Generation Planning group.

3.5 Firm Transportation Forecast

The firm transportation forecast consists of special contract customers and customers on the Firm Transportation Service (FT) rate schedule. The firm transportation revenue class consists of the company’s largest natural gas customers. For forecasting purposes, the largest commercial and industrial customers in this class are forecasted separately. These forecasts are developed by the Sales Analysis & Forecasting department with input from Major Account representatives to make sure the underlying assumptions and forecasted volumes are reasonable.

3.5.1 Industrial Special Contract (ISP) Forecast

LG&E has one industrial special contract gas customer. The inputs to this forecast are provided by the Major Accounts department.

3.5.2 Industrial Firm Transportation (IFT) Forecast

The largest customers in the IFT class make up about two-thirds of the class’s total usage and are forecasted with direct input from account managers. Volumes for the other customers are forecasted in total as a function of heating degree days, gas supply cost, industrial production indices, and binary variables to account for anomalies in the data.

3.5.3 Commercial Firm Transportation (CFT) Forecast

CFT volumes are forecasted as a function of heating degree days, economic indices, and binary variables to account for anomalies in the data.

3.6 Rider TS-2 Transportation Forecast

The TS-2 transportation forecast consists of commercial and industrial customers with a Gas Transportation Service (TS-2) service rider. The rate forecast is the sum of projections for individual customers that are expected to be on the rate in any given period.

3.7 Interdepartmental Transport Forecast

The interdepartmental transport forecast consists of gas used by the Paddy’s Run generating station. The forecast of gas used by this station is provided by the Generation Planning group.

4 Data Processing

The models discussed in the preceding section produce forecasts on a "billed" basis. All customers are assigned to one of 20 billing cycles. A billing cycle determines what time of the month, generally, a customer's meter is read. The volumes on customers' bills are referred to as "billed" volumes. If a customer's billing cycle does not coincide directly with the boundaries of calendar months, that customer's bill will include volumes from multiple calendar months.

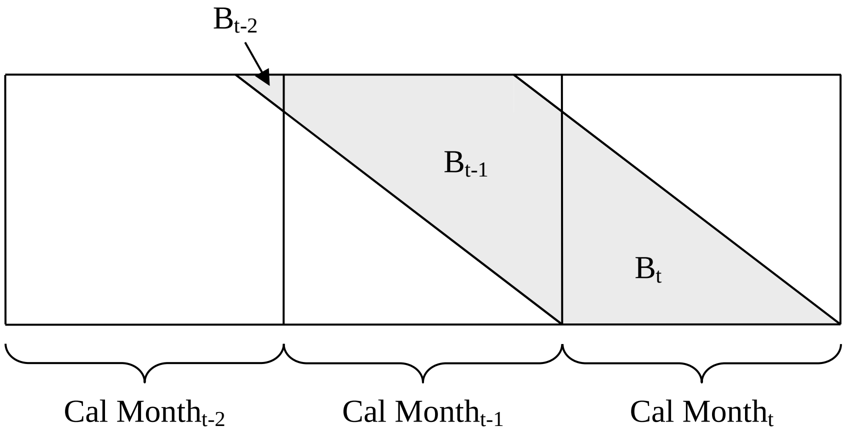
In this part of the forecast process, the billed forecast data is processed to meet the needs of the forecast's end users. First, the billed forecasts are converted from a billed basis to a calendar month basis. Then, the calendar forecasts are allocated by rate and revenue class for use by the Financial Planning Department. In addition, the calendar forecasts are used – along with forecasts of gas losses and gas used by company-owned facilities and generating assets – to produce the Gas Supply Composition Forecast. Each of these processes is discussed in the following sections.

4.1 Billed-to-Calendar Conversion

The following forecasts must be converted from a billed to calendar basis: RGS, CGS, and IGS. The remaining forecasts are billed at the end of each calendar month; thus, their "billed" volumes are already stated on a "calendar month" basis and a billed-to-calendar conversion is not necessary.

The shaded area in Figure 2 represents a typical billing month (B). Area B_t represents the volumes in the billing month that were consumed in the current calendar month (time = t). Area B_{t-1} represents the volumes in the billing month that were consumed in the previous calendar month (time = t-1). Area B_{t-2} represent the volumes in the billing month that were consumed in the calendar month two months prior to the current month (time = t-2).[7] In this process, ratios of historical monthly calendar sales by revenue class to annual monthly calendar sales by revenue class are developed to allocate forecasted billed sales to calendar sales.

Figure 2 – Billed and Calendar Energy



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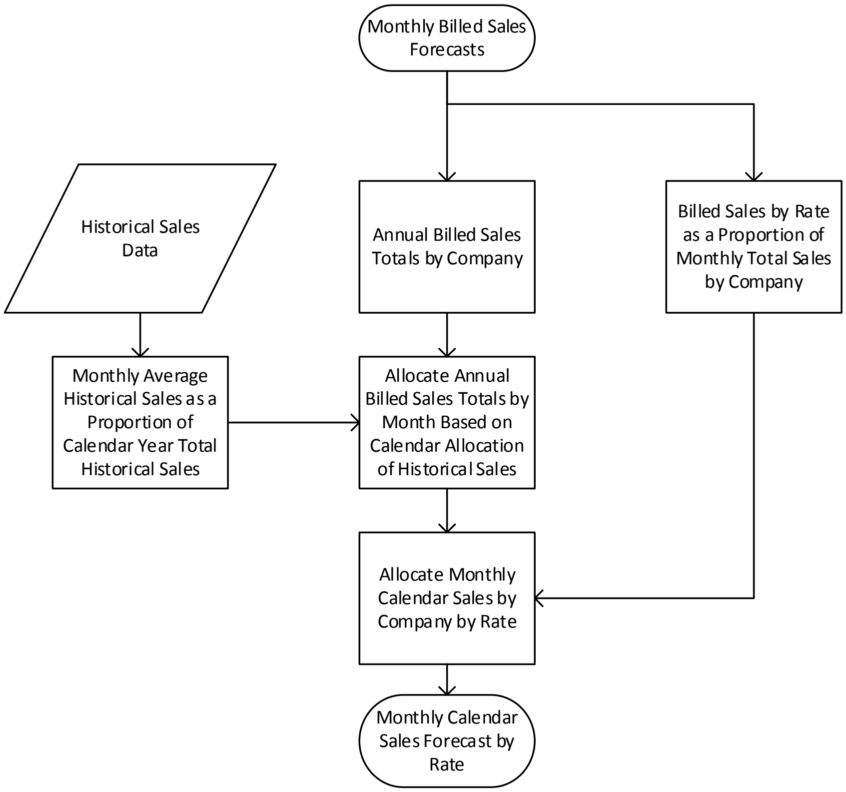
[7] Not all billing months include volumes that were consumed in the calendar month two months prior to the current month.

Using historical calendar data to obtain monthly allocation ratios, the annual billed sales forecasts are allocated into months using the monthly allocation ratios. This yields monthly calendar sales forecasts. These monthly calendar sales are then allocated into rate categories (i.e., tariffs) using the ratio of billed sales by rate to total sales. Figure 3 shows a diagram of the process.



4.2 Rate Class and Revenue Class Allocation

To meet revenue forecasting requirements, the billed and calendar energy forecasts must be allocated by rate group and revenue class. Revenue class is a higher level grouping that aggregates portions of each rate class into a corresponding revenue class. All rate classes are allocated to one of the following revenue classes:

- Residential
- Commercial
- Industrial
- Interdepartmental
- Transport

This information is used by the Financial Planning department to develop a forecast of revenues for the planning period. Billed and calendar forecasts are allocated by rate group and revenue class using a set of monthly allocation ratios. These ratios are derived based on historical sales data from CCS for gas volumes and customers.

4.3 Customer Forecasts

The customer forecasts are used in the company's revenue forecast to compute revenue from customer charges.

The customer charge for the CGS and IGS rate plans varies based on the capacity of the customer's meter – whether it's less than or greater than 5,000 cf/hr. Therefore, information from CCS is used to segment the total number of CGS and IGS customers into these two meter capacity categories.

PPL companies

2015 Business Plan
Gas Volume Forecast

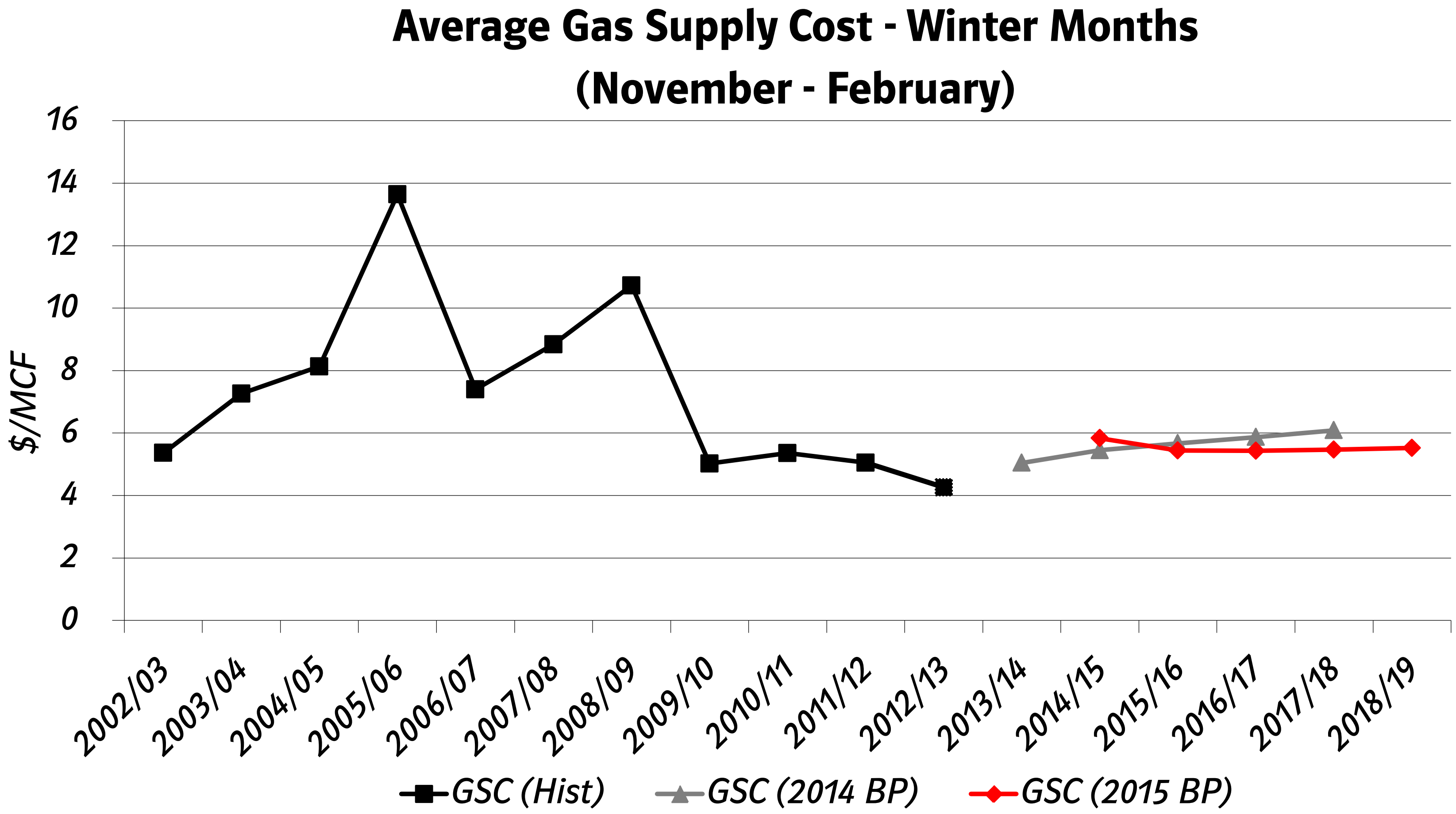
July 11, 2014

Key Forecast Inputs

- *Economy: Indicators for the Kentucky economy remain mixed. RGSP is still low and unemployment is unchanged, but housing statistics are strong.*
    - *Louisville MSA unemployment still at 8.1% in February 2014 compared to 8.2% in March 2013.*
    - *12-month rolling change for housing permits in Louisville is 6.1%.*
    - *RGSP expected to grow at an average of 2.3% over the next 4 quarters.*
- *Customer Growth: Increased expectations for Residential and Commercial customer counts compared to 2014 Plan. Commercial customers expected to continue slow decline in near term.*
- *Major Accounts: Higher usage in 2013 driven by Ford, GE, and American Synthetic increases the Major Account forecast compared to last year.*

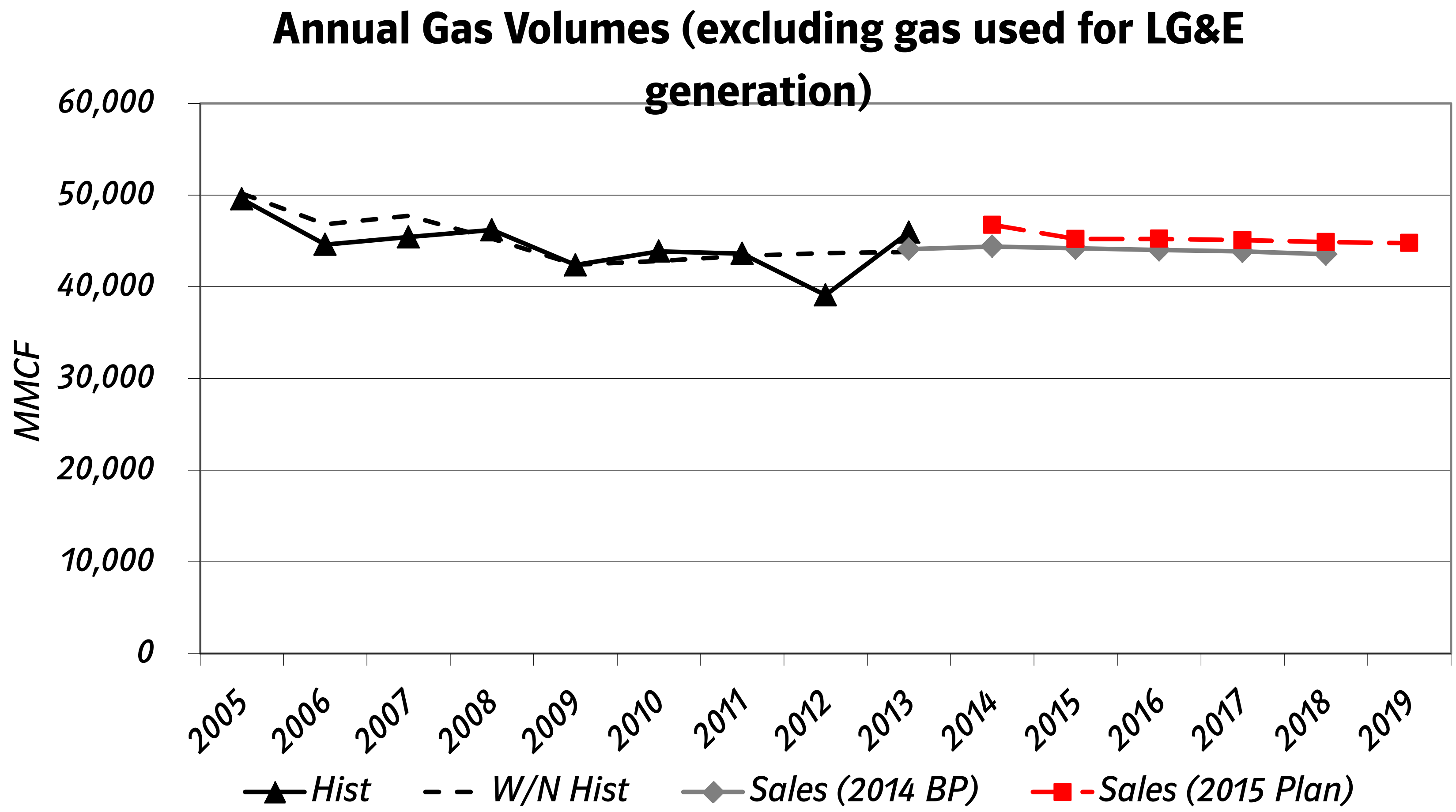
PPL companies

Gas supply cost for winter 2014/15 is expected to be 7.1% higher plan to plan, but lower with flat growth beyond 2014/15


Average Gas Supply Cost - Winter Months
(November - February)

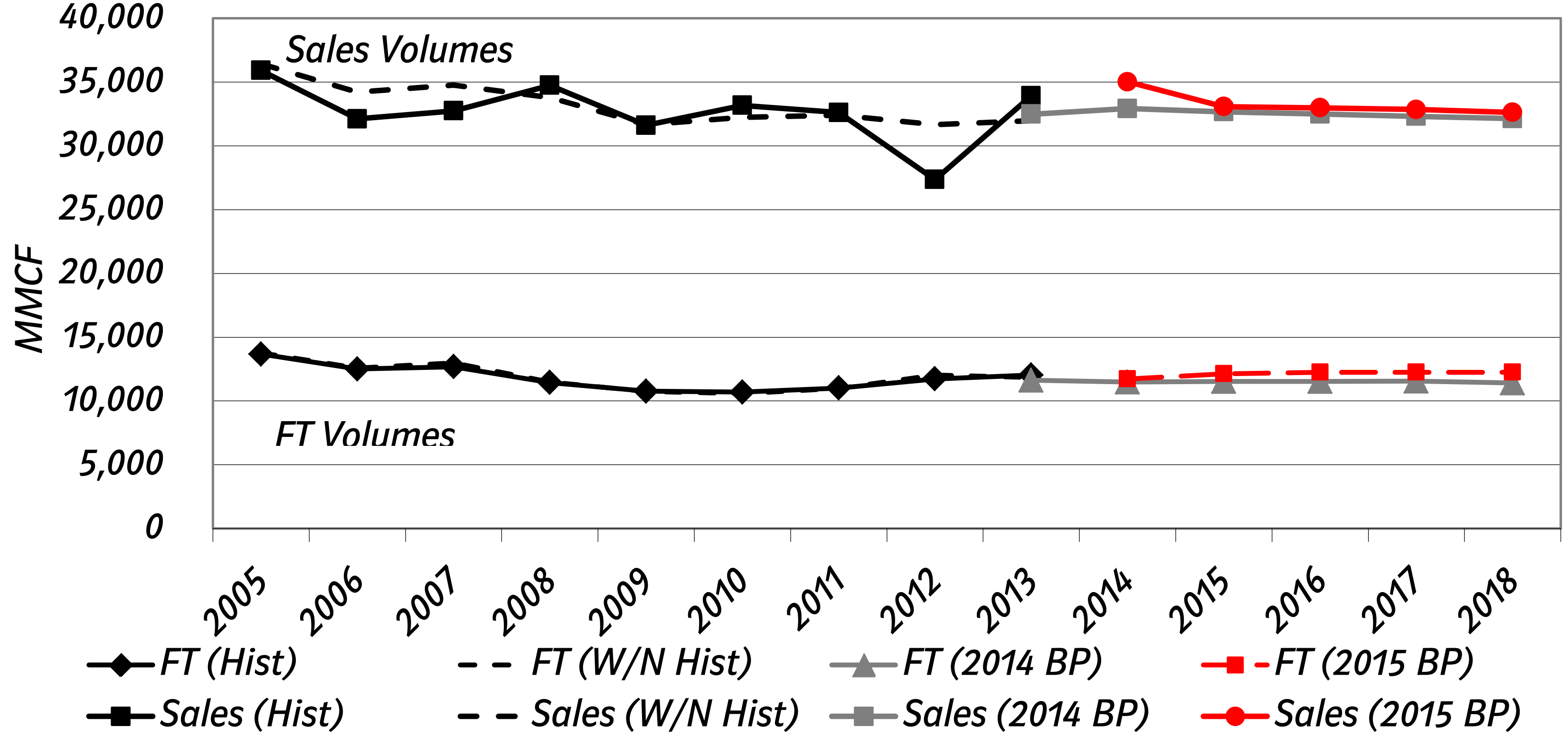
PPL companies

Strong Industrial growth driving total volumes higher



2014 value for the 2015 Plan includes 3 months of WN Actuals

Sales and Transportation volumes are forecasted to be slightly higher than 2014 Plan

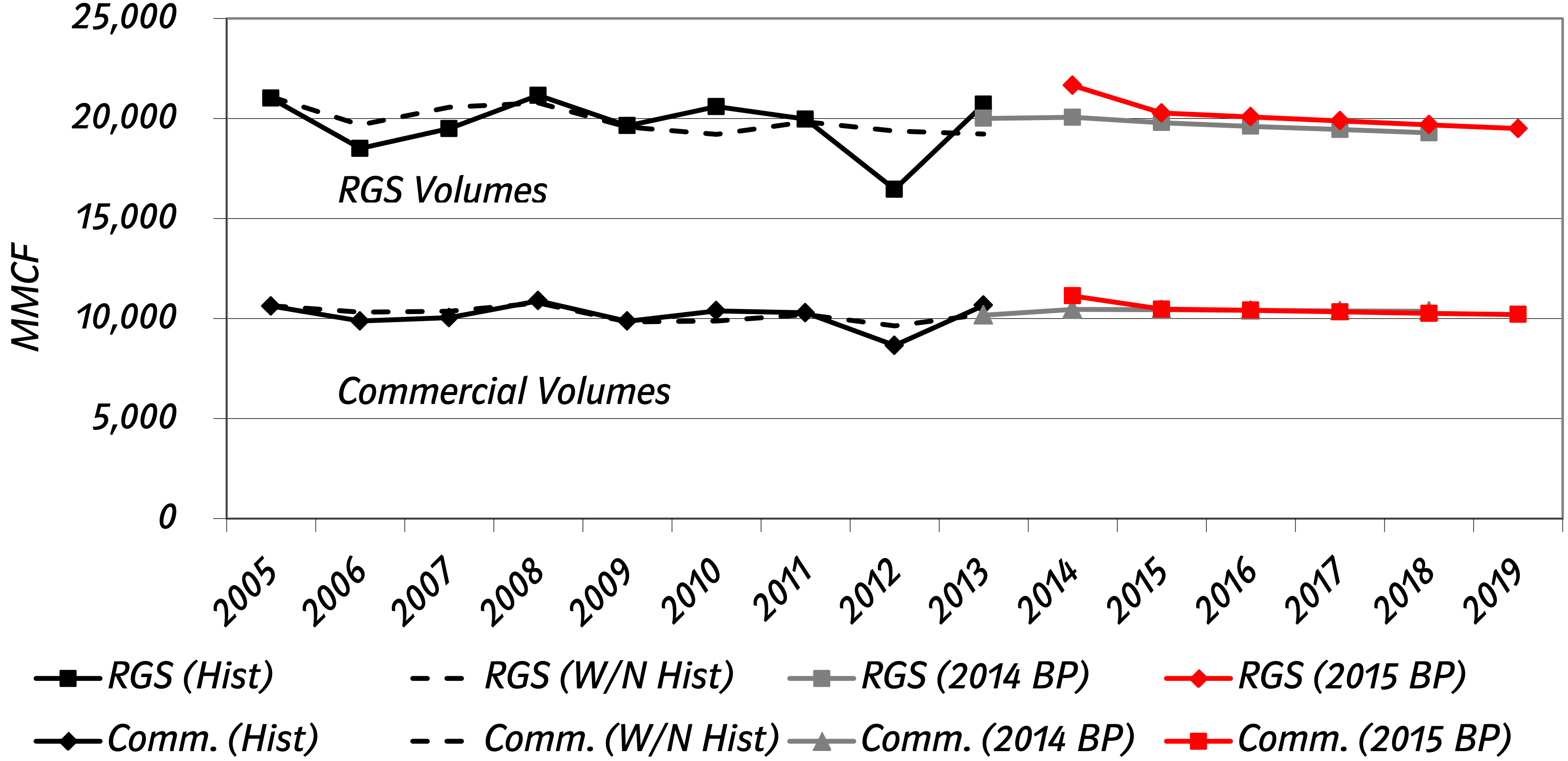


Annual Sales & Firm Transportation (FT) Volumes
(excluding gas used for LG&E generation)

2014 value for the 2015 Plan includes 3 months of WN Actuals

RGS and Commercial annual volumes forecasted to be higher than 2014 Plan in 2014 and 2015

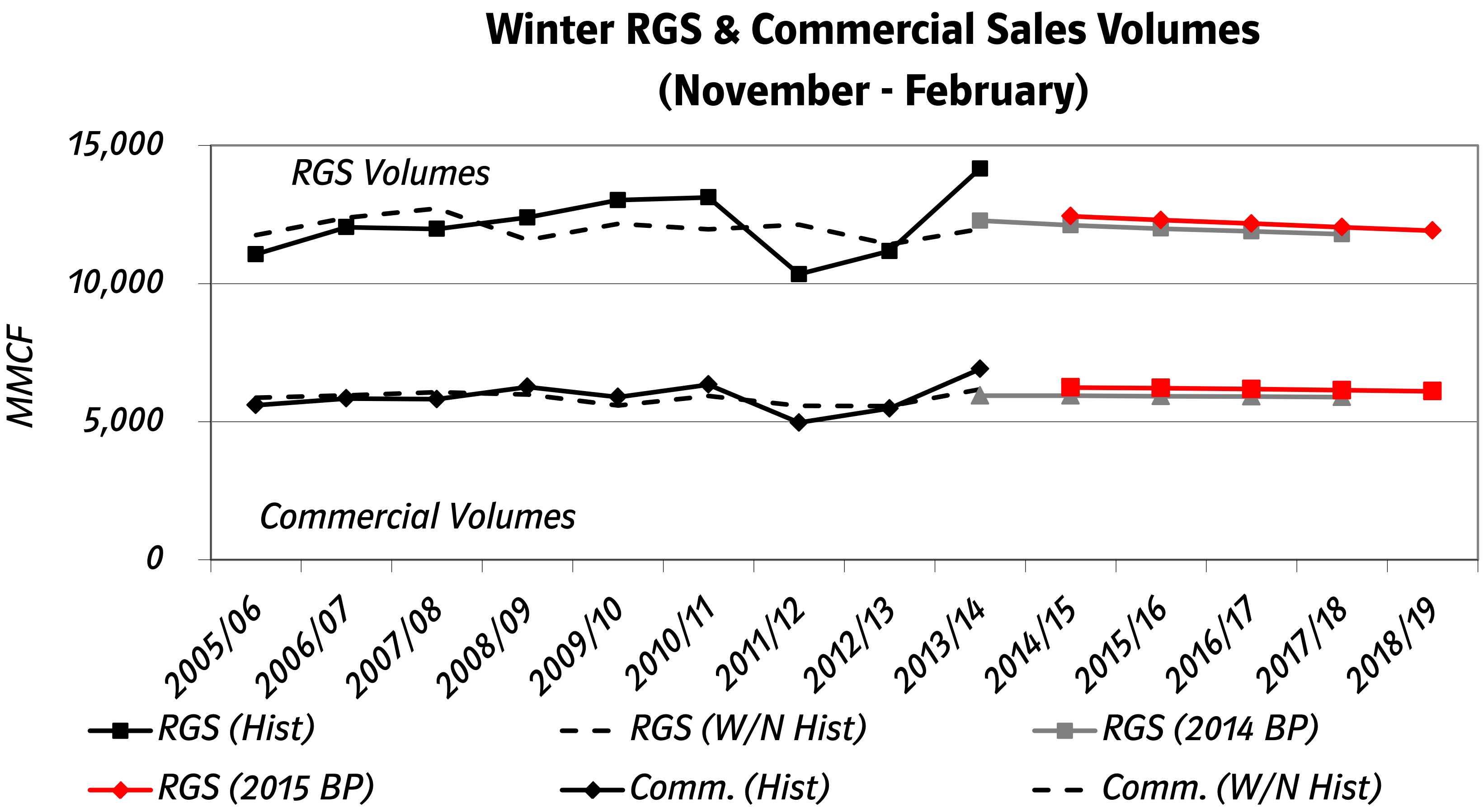
Annual RGS & Commercial Sales Volumes



2014 value for the 2015 Plan includes 3 months of WN Actuals

PPL companies

Compared to the 2014 Plan, RGS volumes are slightly higher for the winter of 2014/15



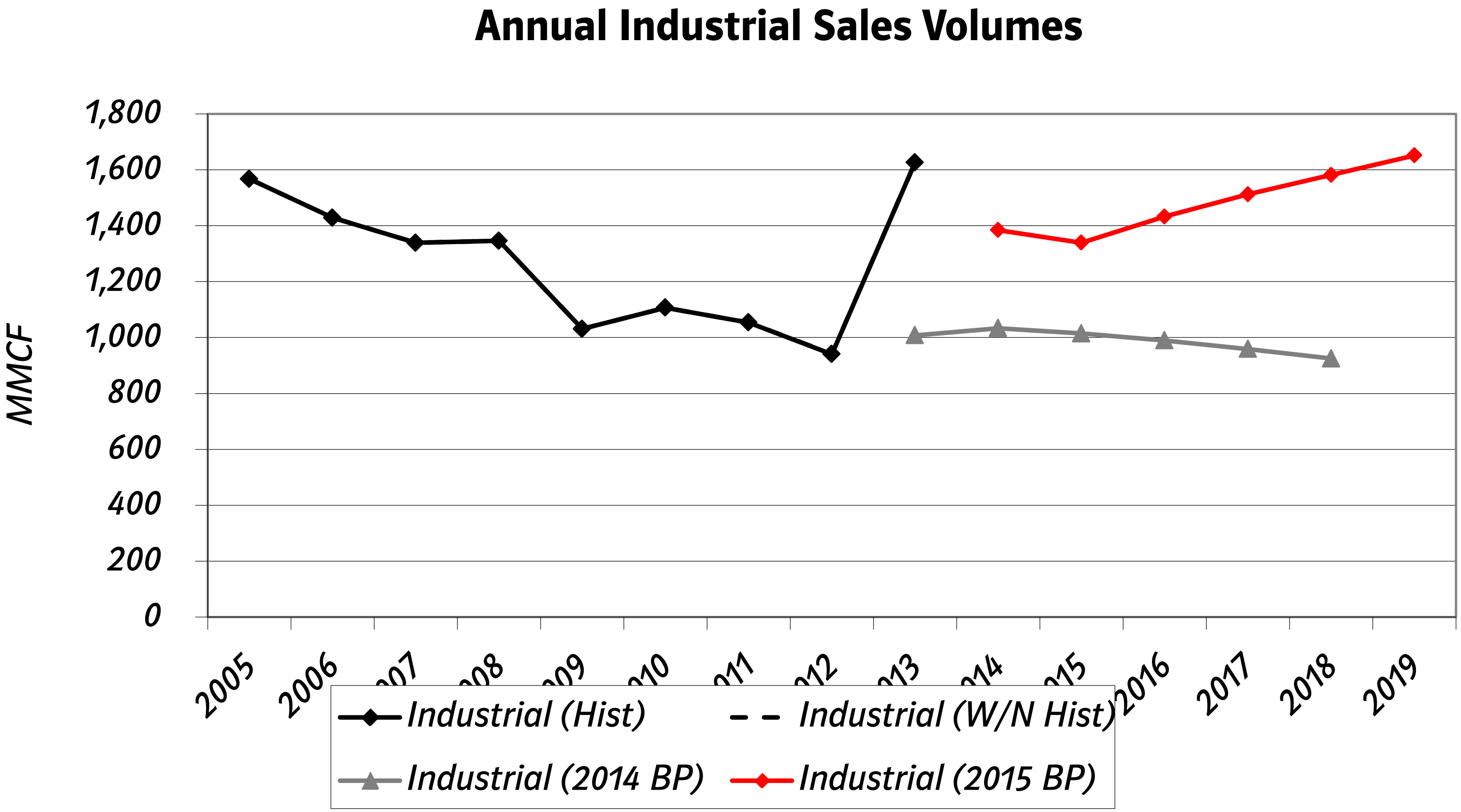
2014 value for the 2015 Plan includes 3 months of WN Actuals

LG&E KU
PPL companies

Summary of Residential Gas Sales Forecasts

- *Higher customer forecast reflects improving housing market and trends in recent history.*
- *EIA increased home size projections based on Census Bureau data. Results in slightly higher natural gas sales forecast.*
- *Heating efficiencies remain largely unchanged from the 2014 BP.*

Industrial sales increase driven by rate switching (FT to IGS)

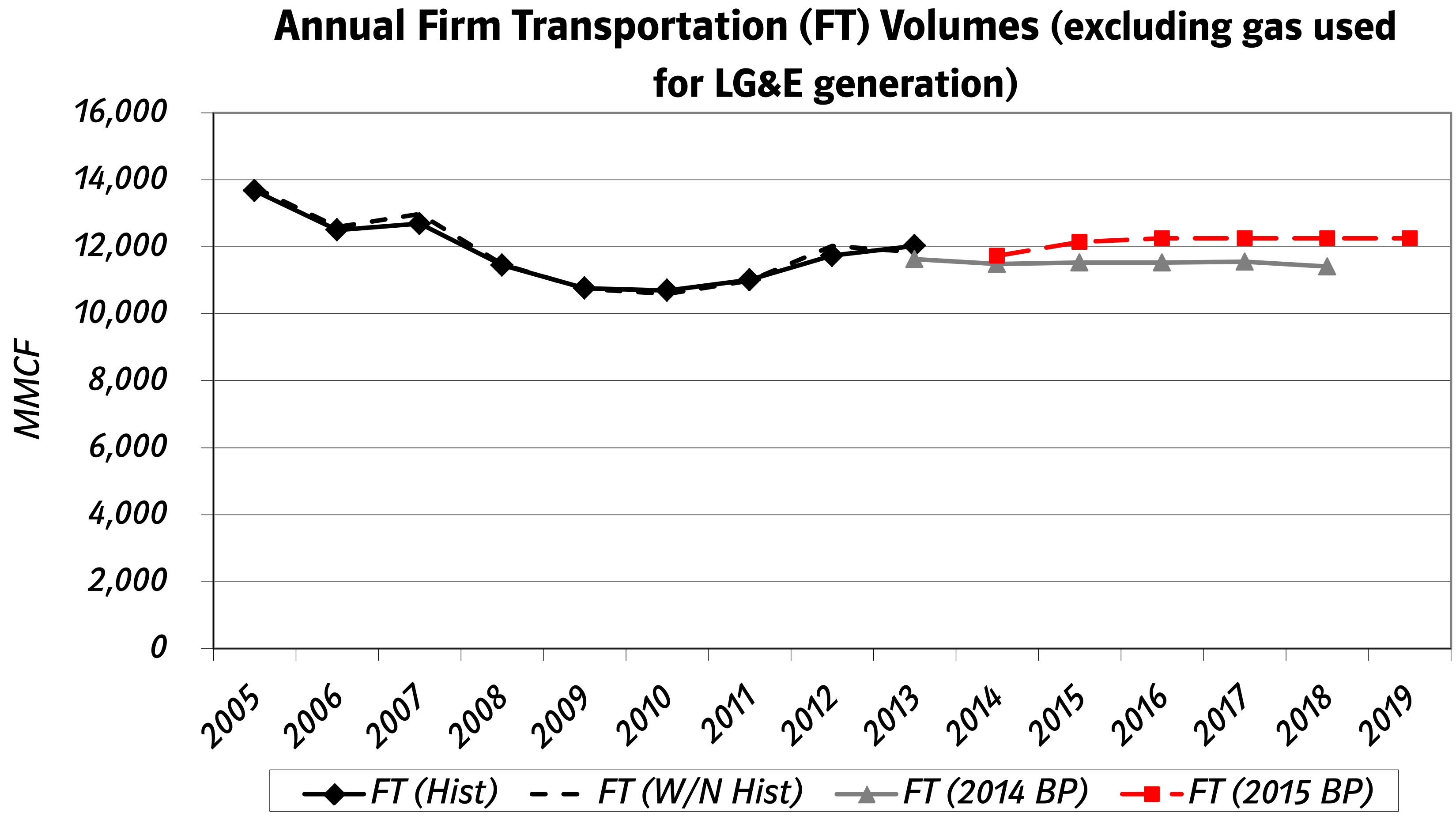


Annual Industrial Sales Volumes

2014 value for the 2015 Plan includes 3 months of WN Actuals

PPL companies

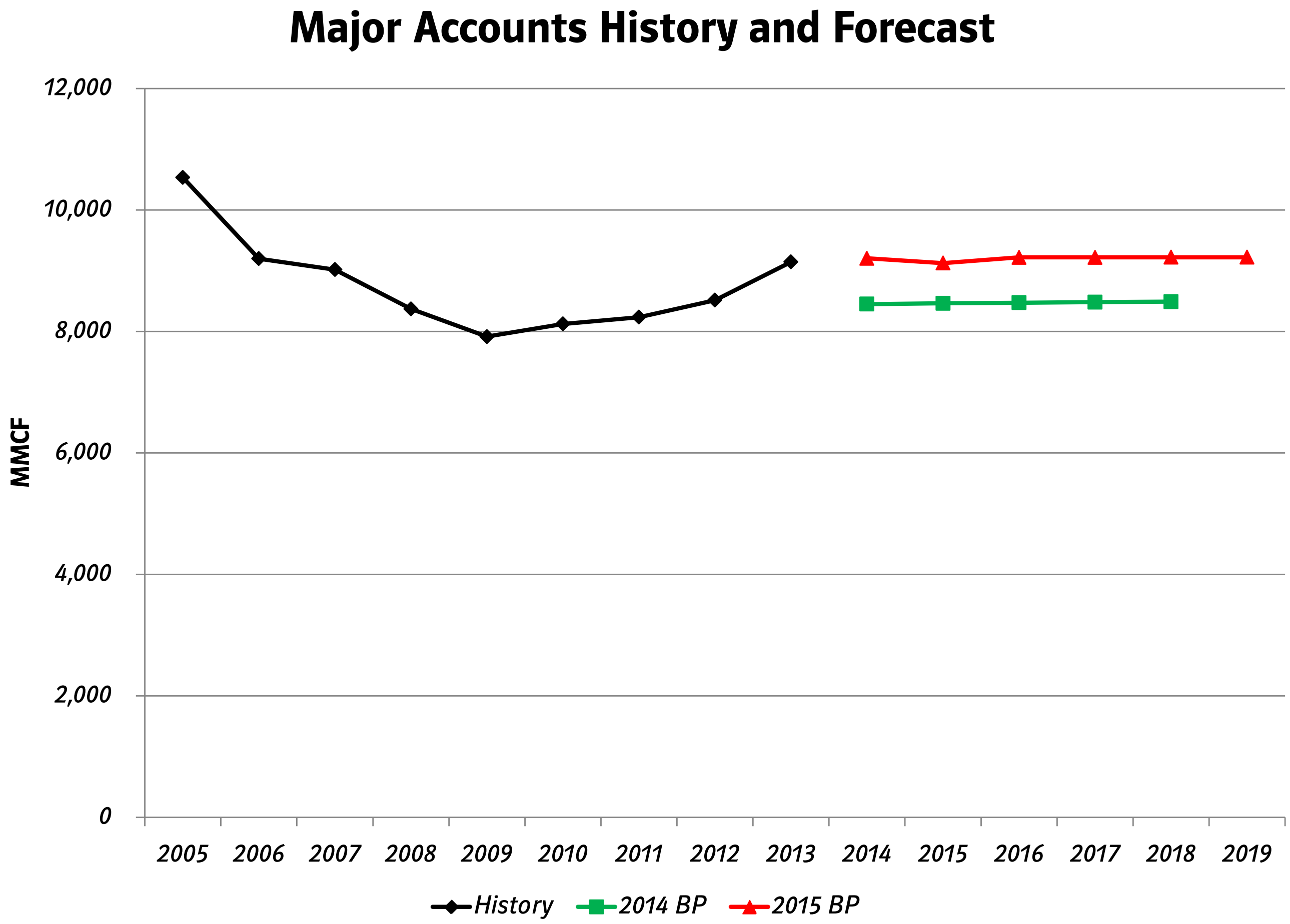
Firm Transportation (FT) volumes higher after growth in 2012 and 2013



2014 value for the 2015 Plan includes 3 months of WN Actuals

LG&E KU
PPL companies

2015 Plan driven by increased usage from Ford, American Synthetic, and GE



2014 value for the 2015 Plan includes 3 months of Actuals

Key Points and Significant Drivers

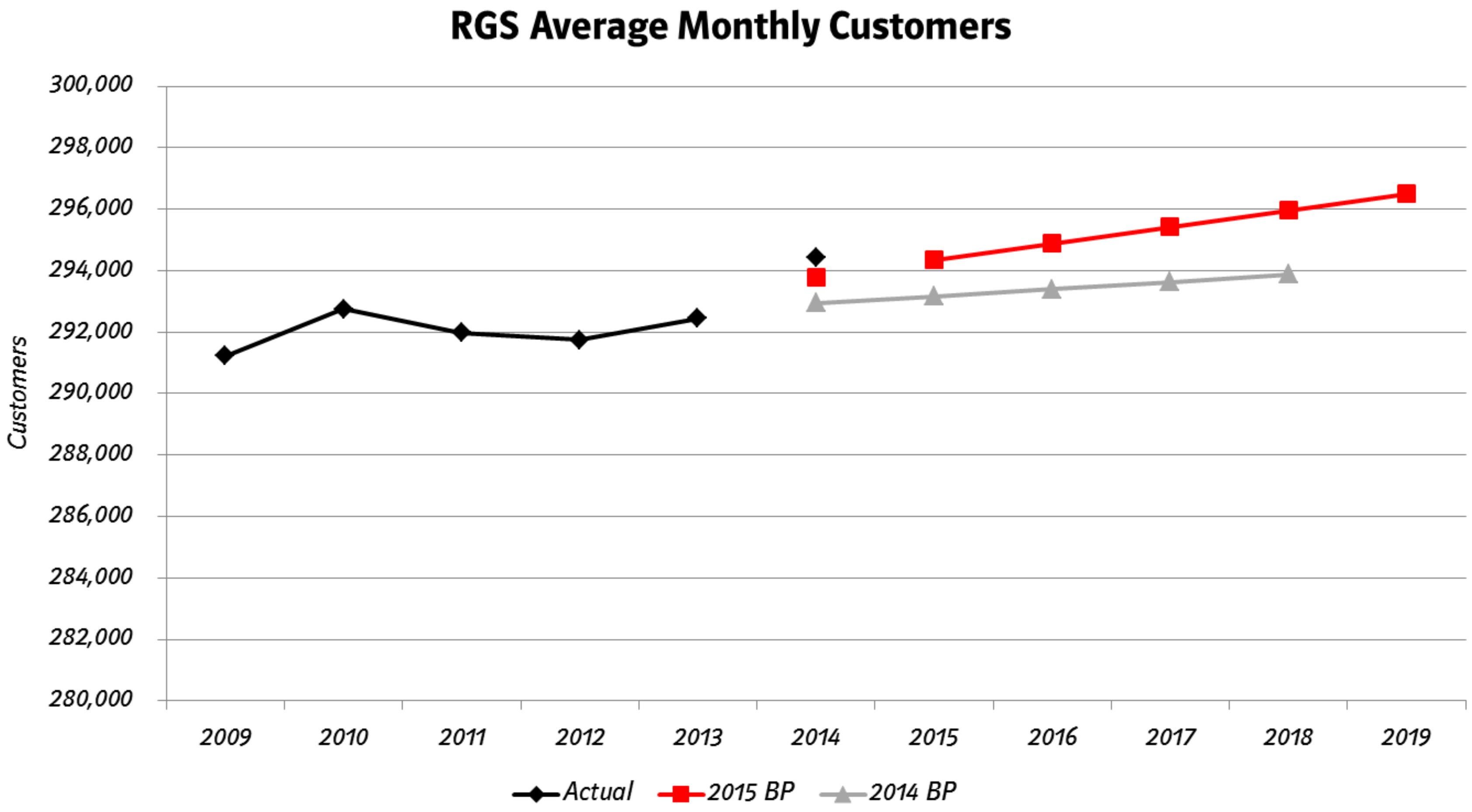
- *Of the 25 individually forecasted customers in the 2015 Plan, 16 have higher forecasts than last year, 7 have lower forecasts than last year, and 2 forecasts did not change*
  - *American Synthetic usage in 2015 is expected to be 24% (197,000 MCF) higher than the 2014 BP*
  - *Ford LAP is expected to continue recent strong usage as Escape production continues to be strong. Usage for 2015 is expected to be 20% (188,000) higher than the 2014 Plan.*
  - *Ford KTP expansion expecting additional gas usage of 182,906 MCF by November 2015.*
  - *GE is expected to be 18% (86,000) higher than the 2014 Plan as a result of a new paint system*

PPL companies

Appendix

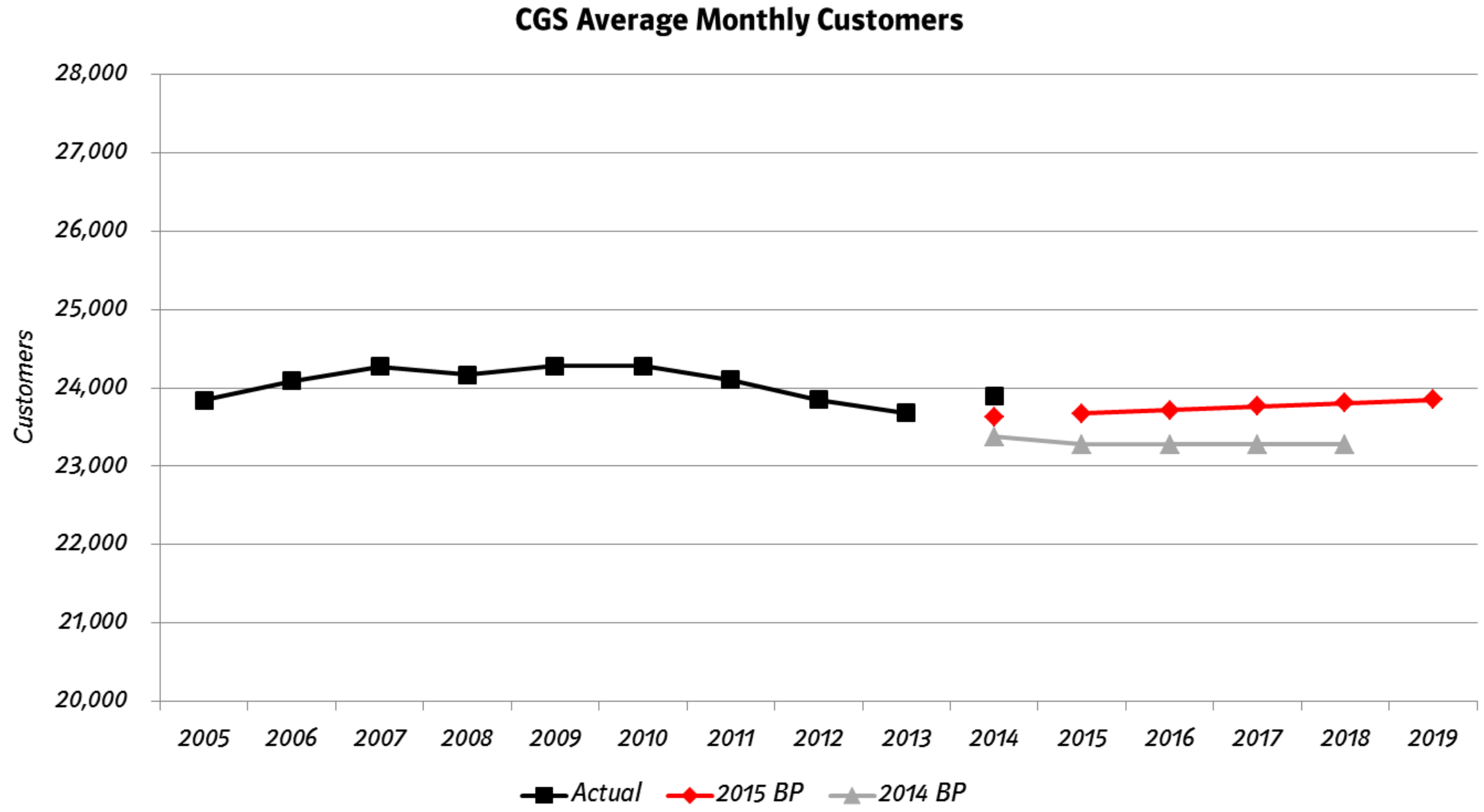
PPL companies

RGS Customer forecast higher than 2014 Plan



PPL companies

CGS Customer forecast showing slight increase



PPL companies

Annual Generation & Off-System Sales Forecast Process

PPL companies

Generation Planning & Analysis
September 2014

Table of Contents

1 Introduction

The Generation Planning group prepares an annual 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 and OSS forecast.

2 Production Cost Model

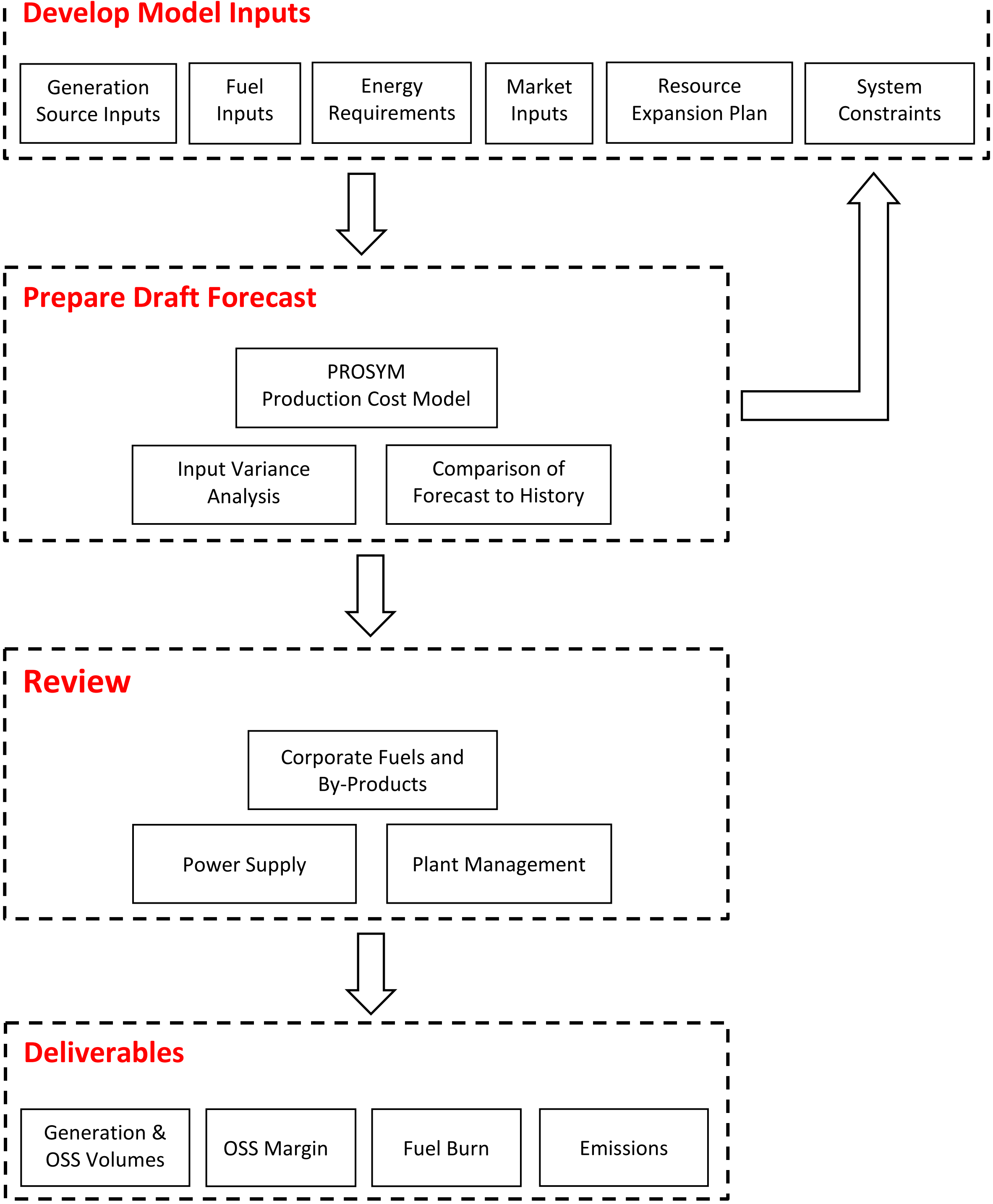
The Companies' generation and OSS forecast is developed using Ventyx's PROSYM, a proprietary production cost model. PROSYM is a chronological simulation engine that optimizes unit commitment and economic dispatch to meet the load for an interconnected electric system, considering the reserve requirements 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 and OSS forecast. In the first part of the process, model inputs are developed. Then, the model inputs are loaded into PROSYM and a draft generation and OSS 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 and OSS 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 and OSS 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 and OSS Forecast Process



3.1 Develop Model Inputs

The first part of the process used to develop the Companies' generation and OSS 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 and OSS Forecast

Input Category	**Inputs**
Generation Source 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 Source Inputs

The generation sources modeled in PROSYM include the Companies' existing sources of generation as well as future generation sources planned to meet customers' growing demand for energy. Generation sources 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 source inputs define the operating characteristics of the generation sources. These inputs include the source'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 source 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 source 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"), mercury ("Hg"), and carbon dioxide ("CO_2") for each generation source:

- 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. For coal units with flue-gas desulfurization ("FGD") equipment, the SO_2 removal rate ranges between 85% and 99%, depending on the vintage of the 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 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. NO_x emissions vary with the unit's 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. For gas units, NO_X emissions are modeled as a function of an average emission rate (specified in lb/MMBtu). The NO_x emission rate for gas units is estimated by the unit manufacturer.
- Hg Emissions: For coal units, Hg emissions are modeled as a function of the unit's average Hg emission rate (specified in lb/MMBtu). Average Hg emission rates are based on engineering estimates and vary depending on whether the unit is retrofitted with a fabric filter baghouse or sorbent injection controls.
- 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 non-fuel costs that are incurred when operating the generation source. For coal units, variable O&M includes the cost of operating environmental controls and the cost of handling coal combustion residuals. For Cane Run 7, variable O&M includes the cost of operating its environmental controls and the cost of its long-term service agreement ("LTSA"), which is paid quarterly based on the number of starts and operating hours for the unit. The Companies do not have similar LTSAs in place for their simple-cycle combustion turbines ("SCCTs"), so variable O&M for SCCTs is not modeled.

3.1.1.5 Operating Limits

The following operating limits are modeled in PROYSM for each generation source. Each of these inputs is specified based on an analysis of historical data.

- Minimum Down-Time: Minimum down-time is the minimum number of hours after coming offline that a generation source 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 source must remain on-line 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 source can increase its output.
- Ramp-Down Rate: Ramp-down rate is the rate (specified in MW/hour) at which a generation source can decrease its output.

3.1.1.6 Unit Availability

The following unit availability inputs are modeled in PROSYM for each source. These inputs determined the extent a source is available for operation.

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[1] The SO_2 removal rate for coal units without FGD equipment is 0%.

- Planned Maintenance Schedule: The planned maintenance schedule specifies the timing and duration of planned maintenance events. The schedule is developed with input from plant 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 source 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 sources modeled in PROSYM are either wholly or jointly allocated to LG&E and/or KU. For each generation source, 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 source 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 sources 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 of 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. See Appendix 1 for a discussion of the process used to develop this forecast.

3.1.2.2 Natural Gas Prices

A forecast of Henry Hub natural gas prices is developed by the Economic Analysis group. See Appendix 1 for a discussion of the process used to develop this forecast. 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 by the Economic Analysis group. See Appendix 1 for a discussion of the process used to develop this 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. Since the prices of these coals are specified in separate forecast 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 XYZ 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 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 by the Economic Analysis group. See Appendix 1 for a discussion of the process used to develop spot hourly electricity prices.

3.1.4.2 Emission Allowances Prices

Forecasts of emission allowance prices for SO_2, seasonal NO_x, and annual NO_X are developed by the Economic Analysis group. See Appendix 1 for a discussion of the process used to develop these forecasts. The dispatch cost for each unit includes the unit's fuel cost, variable O&M costs, and the cost of emission allowances.

3.1.4.3 Hourly Off-System Sales and Purchase Limits

The OSS and purchase limit inputs determine the maximum quantity (in MWs) of OSS and economy purchases that can be made in any given hour. Since the volatility of available transmission capacity cannot 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. OSS and economy purchase limits are developed to coincide with the 95th percentile of the distribution of historical hourly OSS and economy purchase volumes.

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 sources planned to be added to the Companies' generation portfolio to meet customers' growing need for energy and capacity. These generation sources can take the form or new generating units or power purchase agreements with a third-party provider. Generation source inputs are discussed in Section 3.1.1.

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 sources to load under a variety of circumstances. Despite the flexibility that is afforded the Companies, some constraints can occur in real time. For example, at least one generating unit at the Brown Station must be operating at all times to support adequate voltage in the Lexington area. Furthermore, at least one unit at the Green River Station must be on – if possible – at all times to support voltage in western Kentucky. PROSYM models these and other transmission constraints.

3.1.6.2 Spinning Reserve Requirements

As a NERC balancing area, the Companies are required to carry contingency reserves in order to ensure the reliability of the grid. In order to meet these obligations in a least-cost manner, the Companies entered into 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 plant, the Companies need to maintain 258 MW of contingency reserves at all times. In addition, the Companies typically carry approximately 150 MW of regulating reserves in order 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 the 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 prohibits the model from making OSS when SCCTs are operating.

3.1.6.4 Dispatch Order Rules

Dispatch order rules determine the order in which different types of generation sources are dispatched. The majority of generation sources are dispatched economically. However, the Companies' CSR customers are not curtailed until all other company-owned sources have been exhausted. 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 and OSS Forecast

In the second part of the process used to develop the Companies' generation and OSS forecast, model inputs are loaded into PROSYM and PROSYM is used to prepare a draft generation and OSS forecast. 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 and OSS 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 and OSS 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 one input (or group of related inputs). 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 waterfall 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 sampling of forecast elements that are compared to historical data.

- Annual/monthly/hourly generation by generation source
- Annual/monthly fuel burn by generation source
- Annual startup fuel by generation source
- 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 source
- Annual/monthly intercompany transaction volumes
- Annual/monthly dispatch order
- Number of CSR curtailments

3.3 Review

In the third part of the process used to develop the Companies' generation and OSS 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
- Emission Forecasts

Appendix 1 – Commodity Price Forecasts

The Economic Analysis department developed price forecasts for several commodities. The process covering the 2015-2017 period for each of the following commodities is discussed in the subsequent sections.

- Natural gas
- Coal
- Electricity
- Fuel oil
- Emissions allowances

1 Natural Gas

The natural gas price forecast reflects monthly Henry Hub forward market prices from NYMEX as of June 23, 2014 which reflected the most current view of forward prices at the time the forecast was prepared.

2 Coal

For many years, the Companies have used essentially the same coal price forecast methodology as updated and improved over time. For the 2015-2017 period, the Companies' Fuels Department established the desired coal inventory levels by plant. Based on the coal burn forecast by unit developed by the Generation Planning Department, the Fuels Department calculates the target purchase tonnage needed each year to maintain desired inventory levels while meeting the forecasted coal burn.

Once the target purchases are established, the Fuels Department incorporates the current contracts and spot orders in place for their full term with known tonnage volumes and prices. The difference between target purchases and existing contract committed purchases is calculated and labeled as "uncommitted tons" or "open position" in the forecast. The price for the uncommitted tons is estimated based on a combination of current coal bids and coal price forecasts from an independent third party consultant, Wood Mackenzie.

The 2015 price curve forecast was developed from the Wood Mackenzie Long-Term Price Outlook (May 2014). For the first and second year of the forecast, prices for the uncommitted tons are set at the average price level established by coal bids received, but not yet under contract. For each subsequent year of the forecast period, prices for the uncommitted tons are set at a level determined by weighting prices for bids received and prices as forecast by the Wood Mackenzie study. For example, the current forecast prices for 2015 and 2016 for uncommitted tons are forecast at 100% of the average price quoted in the bids received in the spring of 2014. The Companies evaluate the bids received, excluding any non-competitive bids, calculate an average mine price for the individual years' bid, and apply the average price by year to the uncommitted tons. Uncommitted tons for 2017 thru 2019 are priced at a level determined by weighting the price of bids received for those years and the Wood Mackenzie study. Current transportation, barge fleeting, and rail car maintenance costs are added to the forecast price to determine the total forecast delivered price.

3 Electricity

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] Monthly forward market prices for PJM West Hub ("PJM-WH")[3] quoted by Intercontinental Exchange as of June 23, 2014 are used as a basis for developing an hourly forecast of PJM-SI prices, reflecting the most current view of forward prices at the time the forecast was prepared.[4]

Monthly PJM-SI prices are derived by applying seasonal discount factors by peak type to the quoted PJM-WH prices. The discount factors are based on historical ratios between actual PJM-SI and PJM-WH 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. 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 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 ratio of hourly prices to daily prices by month and by peak type.

4 Fuel Oil

The 2015-2017 fuel oil price forecast consists of three segments beginning with market prices that are interpolated to a longer-term forecast.

- 2015 monthly prices reflect NYMEX New York Harbor #2 fuel oil monthly contract settled prices as of 6/2/2014. Due to a lack of market liquidity, forward #2 fuel oil prices past December 2015 are not used.
- 2016 monthly prices are interpolated values between the 2015 and 2017 monthly prices.
- 2017 monthly prices are derived using linear regression to reflect the historical relationship between monthly average prices for NYMEX #2 fuel oil and West Texas Intermediate ("WTI") oil prices. A long-term forecast for WTI prices from IHS is used as a basis for the NYMEX #2 fuel oil forecast.

A 7% delivery basis is added based on the average monthly historical ratio between the monthly average price for fuel oil delivered to LG&E and KU and the monthly average settled price for New York Harbor #2 fuel oil.

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[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.

[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.

5 Emissions Allowances

For SO_2, seasonal NO_x, and annual NO_x emissions allowances, prices are assumed to be constant over 2015-2017 at the market prices as of 6/23/2014 for allowances under the Clean Air Interstate Rule program. No allowance price assumptions are made for the Cross-State Air Pollution Rule (CSAPR) because of the uncertainty regarding how the EPA may implement the program following the Supreme Court's April 2014 ruling to uphold the program. No CO_2 emission cost is assumed during the 2015-2017 period.

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2015 Business Plan
Generation & OSS Forecast

Generation Planning & Analysis
August 13, 2014

2015 Plan Summary

- *Compared to the 2014 Plan, native load production costs ($/MWh) in the 2015 Plan are lower.*
  - *Lower coal prices drive reductions throughout planning period.*

- *OSS contribution is higher in 2015-2017 and lower in 2018-2019.*
  - *Changing electricity and gas prices drive increases in 2015-2017.*
  - *Deferral of Green River 5 drives lower OSS margin in 2018-2019.*

Native Load Production Costs ($/MWh)	**2015**	**2016**	**2017**	**2018**	**2019**	**CAGR**
2014 Plan	*29.79*	*31.23*	*32.81*	*34.15*	*35.09*	*4.2%*
2015 Plan	*29.39*	*29.60*	*31.12*	*32.38*	*33.35*	*3.2%*

OSS Contribution ($M)	**2015**	**2016**	**2017**	**2018**	**2019**
2014 Plan	*1.3*	*0.9*	*1.2*	*1.8*	*3.4*
2015 Plan	*3.0*	*3.1*	*2.1*	*1.6*	*1.9*

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Key Changes in Planning Assumptions & Inputs

- *Plan over plan, coal prices are 1% lower in 2015 and 2-4% lower in 2016-19.*
  - *Electricity and gas prices are higher in 2015, mostly unchanged in 2016, and lower in 2017-2019.*
- *Native load energy requirements are 1% lower in 2015-2018 and 4% lower in 2019.*
  - *Economic growth still slow.*
  - *Departure of 10 municipal customers (~320 MW) by May 2019.*
- *Variable O&M forecast for new environmental controls is lower at the Ghent, Mill Creek, and Brown stations; slightly higher at the Trimble County station.*
- *Consistent with history, modeled OSS limits reduced from 600 MW/hr to 400 MW/hr in peak and weekend periods; 150 MW/hr in off-peak period.*
- *Expansion plan includes LS Power PPA from May 2015-April 2019, Brown Solar in December 2016, and 2x1 NGCC in May 2021.*
  - *PPA fixed costs (~$10 million in 2015, ~$15 million/year in 2016-2018, ~$5 million in 2019).*
- *Coal unit availability consistent with prior plan except for:*
  - *Green River 3-4 retirement deferred from October 1, 2014 to April 16, 2016*
- *Paddy's Run units available year-round beginning 1/1/2016 (pending completion of gas pipeline project).*

PPL companies

Modeled EFOR assumptions are mostly unchanged

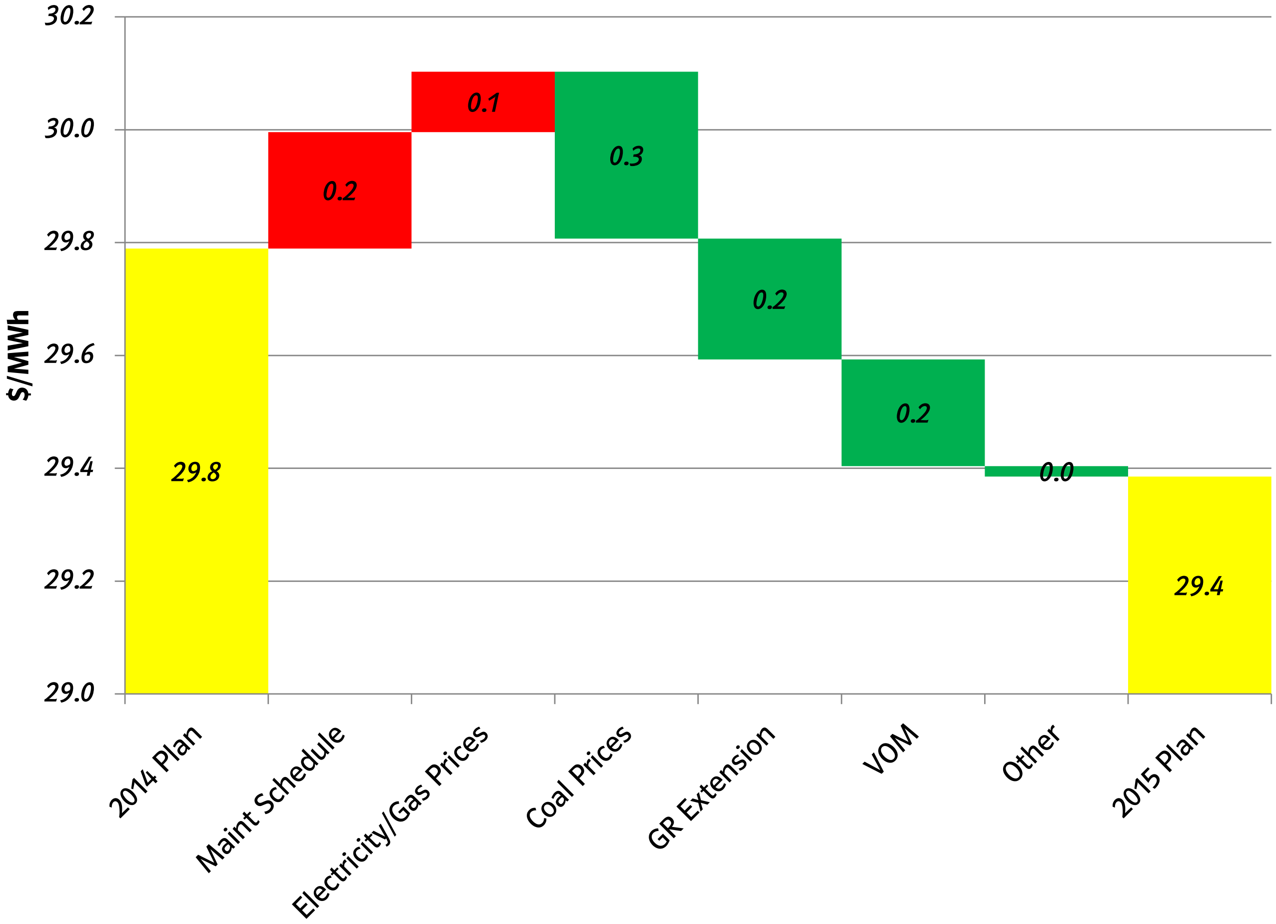
- *Modeled EFOR for TC2 increased from 5.6% to 6.0% in 2015.*
  - *In 2015 Plan, modeled EFOR assumption for TC2 remains constant throughout planning period.*

Modeled
EFOR Assumptions for 2015

	2014 Plan	**2015 Plan**	**Difference**
BR1	**5.6%**	**5.6%**	**0.0%**
BR2	**5.6%**	**5.6%**	**0.0%**
BR3	**5.6%**	**5.6%**	**0.0%**
CR4	**8.1%**	**8.1%**	**0.0%**
CR5	**8.1%**	**8.1%**	**0.0%**
GH1	**5.6%**	**5.6%**	**0.0%**
GH2	**5.6%**	**5.6%**	**0.0%**
GH3	**5.6%**	**5.6%**	**0.0%**
GH4	**5.6%**	**5.6%**	**0.0%**
GR3	**8.1%**	**8.1%**	**0.0%**
GR4	**8.1%**	**8.1%**	**0.0%**
MC1	**5.6%**	**5.6%**	**0.0%**
MC2	**5.6%**	**5.6%**	**0.0%**
MC3	**5.6%**	**5.6%**	**0.0%**
MC4	**5.6%**	**5.6%**	**0.0%**
TC1	**5.6%**	**5.6%**	**0.0%**
TC2	**5.6%**	**6.0%**	**0.4%**
CR7	**7.0%**	**7.0%**	**0.0%**
	Generation Weighted Average		
Coal and NGCC	**5.8%**	**5.9%**	**0.1%**
Coal Only	**5.7%**	**5.8%**	**0.1%**

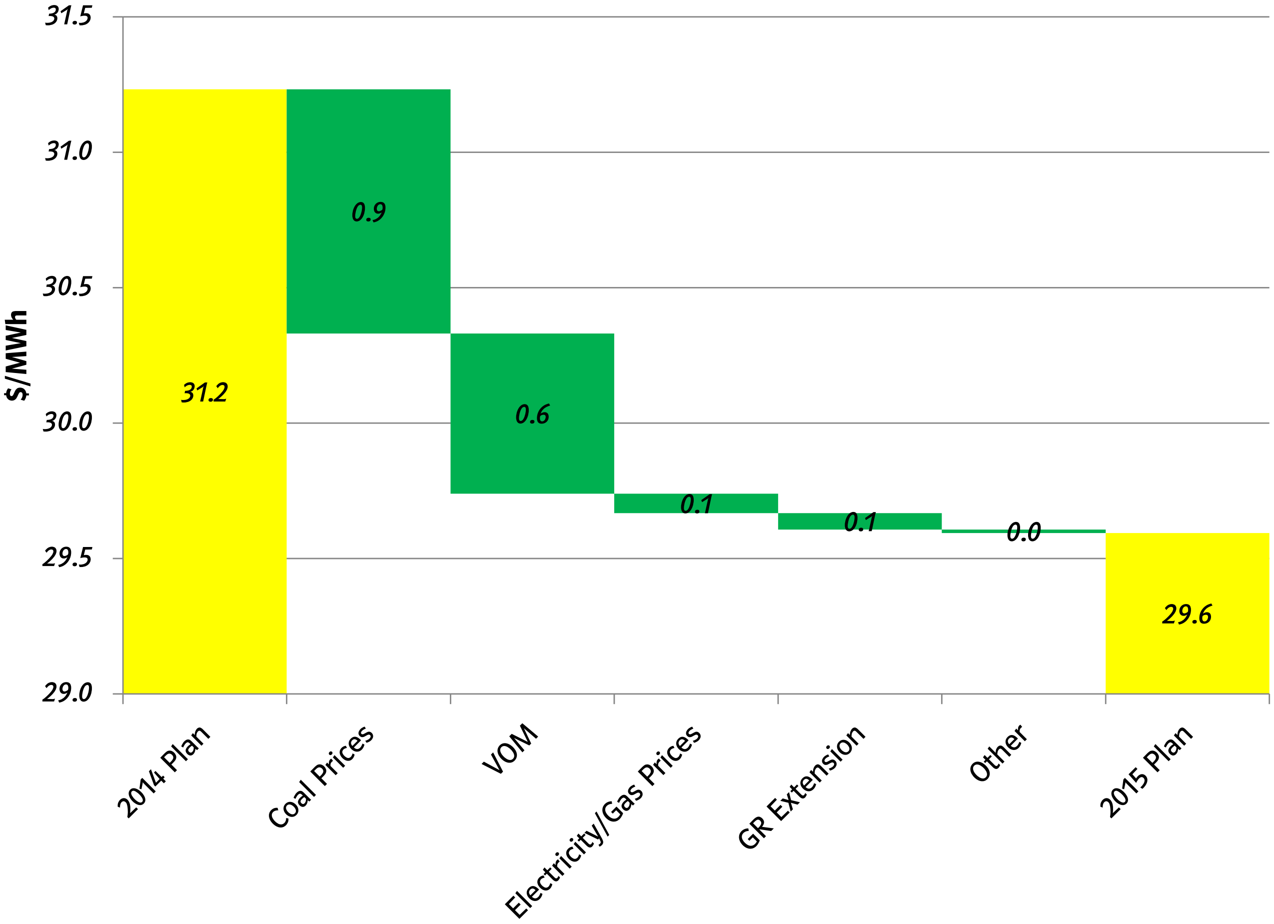
Note: CR6 will not operate in 2015 unless it is needed to ensure system reliability.

In 2015, lower coal prices, the Green River extension, and lower variable O&M are the key drivers of lower native load production costs



PPL companies

In 2016, lower coal prices and variable O&M are the key drivers of lower native load production costs



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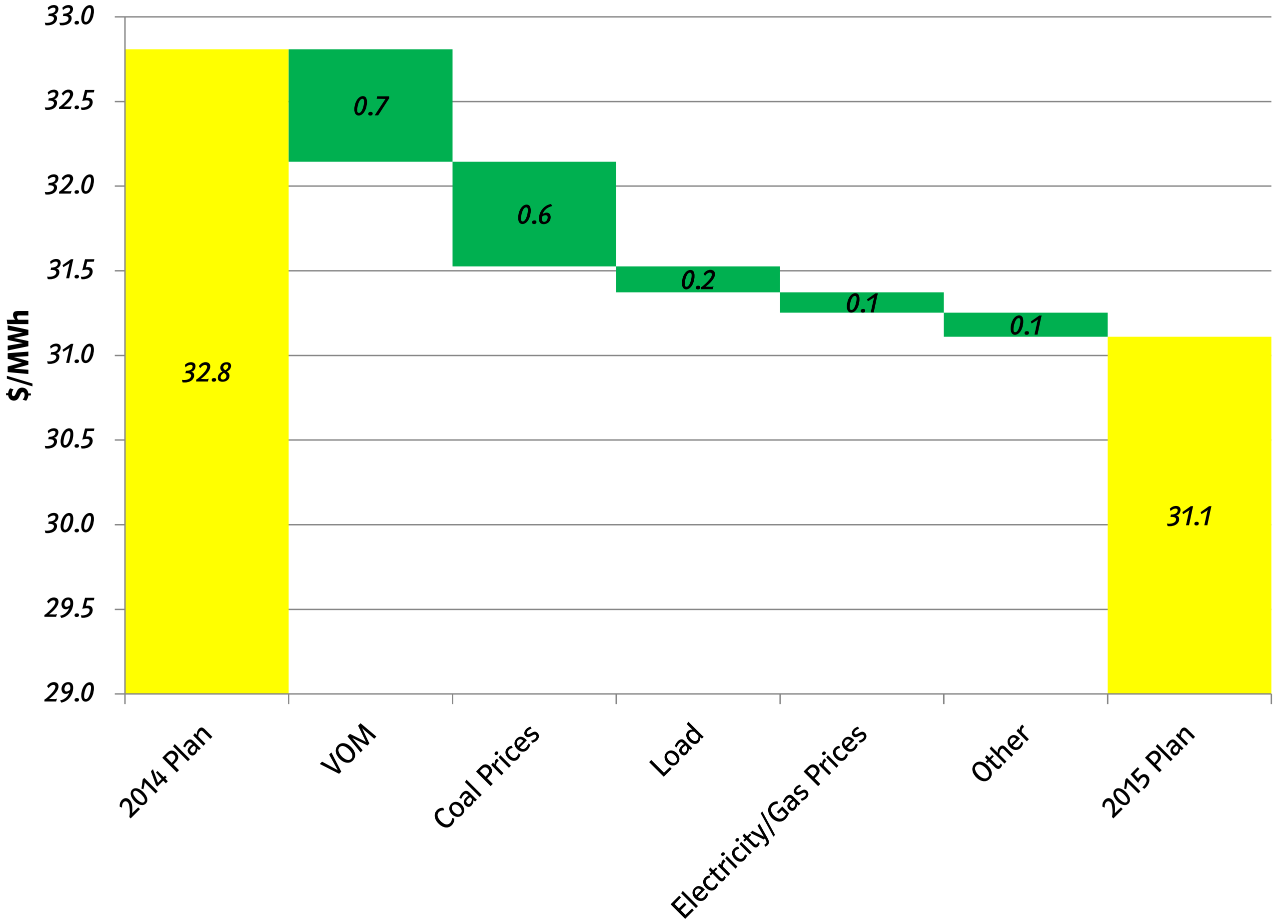
In 2017, lower coal prices and variable O&M are the key drivers of lower native load production costs



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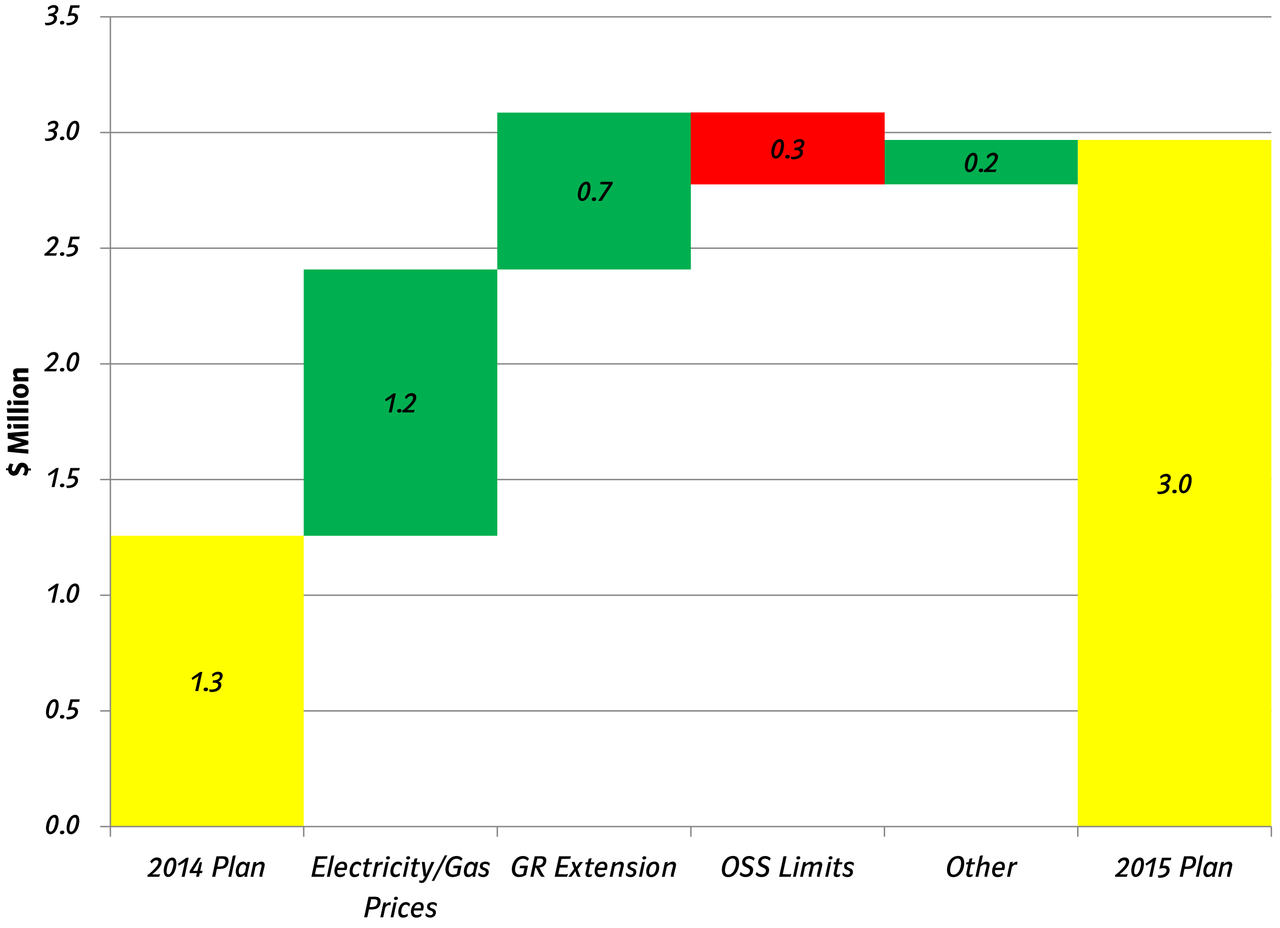
In 2015, higher electricity prices and the Green River extension are the key drivers of higher OSS contribution



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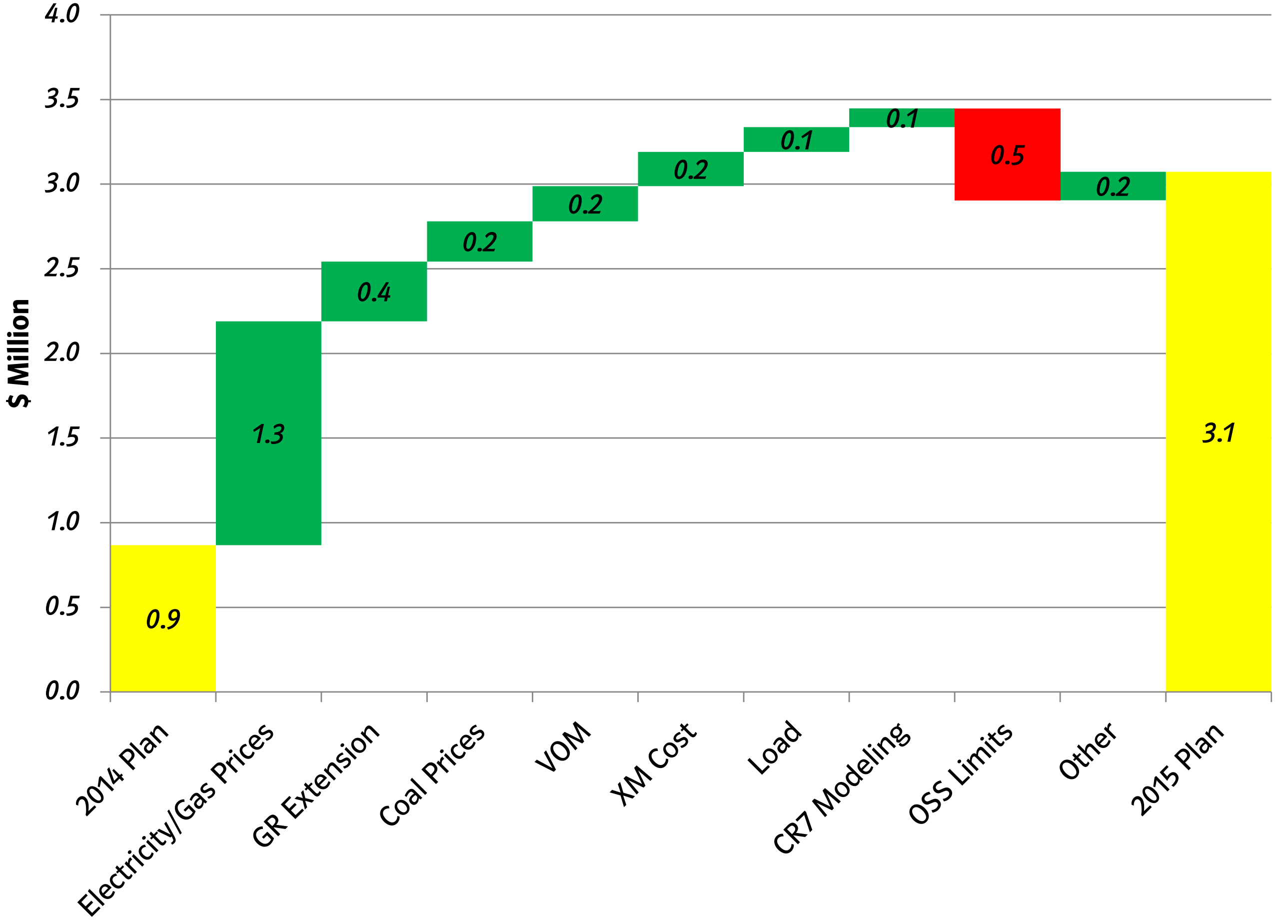
In 2016, higher electricity prices and the Green River extension are the key drivers of higher OSS contribution



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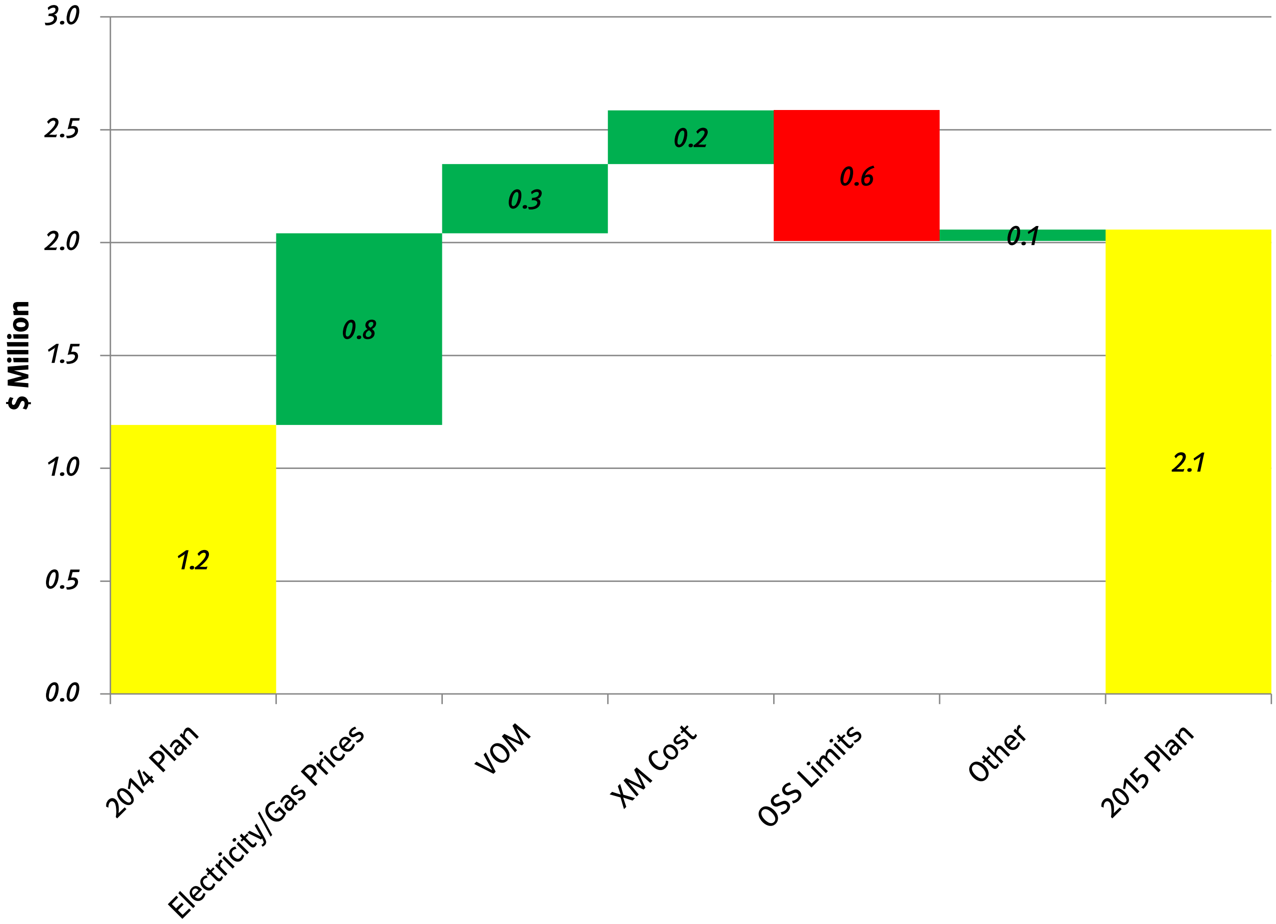
In 2017, lower gas prices drive higher OSS contribution



PPL companies

Key Risks and Uncertainties

- *Short-Term*
  - *Approval of Green River extension*
  - *Trimble County 2 performance post burner replacement*
  - *Cane Run 7 testing, commissioning date, and performance after commissioning*
  - *Coal unit performance in 2015 post installation of environmental retrofits*
    - *Ghent 1: Spring 2015 (baghouse/turbine overhaul)*
    - *Mill Creek 1-2: Spring 2015 (baghouse/FGD)*
    - *Ghent 2: Fall 2015 (baghouse)*
    - *Brown 3: Fall 2015 (baghouse)*
    - *Trimble County 1: Fall 2015 (baghouse)*
  - *Generally, transition of system as we retire small coal units and commission Cane Run 7*
  - *Summer 2016 availability of Mill Creek 3 following baghouse/FGD installation*
- *Long-Term*
  - *Compliance with GHG regulations and effluent guidelines*
  - *Landfill capacity at Mill Creek*

PPL companies

Appendix

PPL companies

2015 Plan – Assumptions

- *Plan EFOR assumptions are based on historical EFOR values. 'Target' EFORs will continue to be the basis for KPI reporting and are mostly unchanged.*
  - *TC2 target EFOR increased from 3.8% to 5.3%.*
- *For the purposes of computing production costs, the following will be assumed:*
  - *Cane Run 6 unavailable 10/1/2014 – 4/30/2015*
  - *4/16/2016 retirement date for Green River 3-4*
  - *5/1/2015 commercial date for Cane Run 7*
  - *5/1/2015 retirement date for Cane Run 4-6*
- *At least one Brown unit must be operating at all times.*
- *At least one Green River unit must be operating at all times.*
- *At least two Cane Run coal units must be operating during June-August; at least one Cane Run coal unit must be operating during rest of year.*
- *Paddy's Run 11-13 unavailable from November through March (gas pressure) through the end of 2015; beginning in January 2016, the Paddy's Run units will be available year-round following the completion of a new pipeline project.*
- *FGDs and SCRs will continue to operate at normal SO_2 and NO_X removal levels.*

PPL companies

2015 Plan – Assumptions

- *Expansion plan:*
  - *Target reserve margin: 16-21%*
  - *LS Power PPA (165 MW): May 2015 – April 2019*
  - *Brown Solar (9 MW): December 2016*
  - *2x1 NGCC (670 MW): May 2021*
- *Spinning reserve requirements:*
  - *Contingency: Spinning 258 MW, (100 MW of 258 MW is supplemental - supplied by quick-start units)*
  - *75 MW regulating*
  - *75 MW NAS*
- *Off-system sales cannot be generated by CTs (same assumption in 2014 Plan)*
- *Baghouse installation schedule:*
  - *2014: GH3 (completed), GH4, MC4*
  - *2015: BR3, GH1, GH2, MC1, MC2, TC1*
  - *2016: MC3*

PPL companies

2015 Plan – Assumptions

- *FGD installation schedule*
  - *2014: new MC4 FGD*
  - *2015: Combined MC1 & 2 FGD*
  - *2016: new MC3 FGD*
- *No turbine upgrades*
- *Turbine overhaul schedule*
  - *2014: MC4, GH4*
  - *2015: GH1, BR1*
  - *2016: None*
  - *2017: BR2, TC1*
  - *2018: GH3, TC2*
  - *2019: GH2, BR3, MC3*
- *Market volume limits*
  - *Hourly sales limited to 400 MW/hr in peak and weekend periods; 150 MW/hr for off-peak period*
  - *Hourly purchases limited to 200 MW/hr in all peak periods*
- *Market electricity prices*
  - *Consistent with July-approved prices*
  - *Hourly prices are correlated with forecasted load shape*

PPL companies

2015 Plan – Assumptions

- *CAIR continues through 2015.*
- *With the addition of Cane Run 7 and the retirement of the Cane Run and Green River coal units, the plan assumes generation portfolio is well-positioned for more stringent SO_2 and NOx rules that may take effect beginning in 2016.*

Emission Allowance Prices ($/ton emitted)

Year	Annual NOx	Seasonal NOx	SO_2
2015	64.50	27	1.75
2016	64.50	27	1.75
2017	64.50	27	1.75
2018	64.50	27	1.75
2019	64.50	27	1.75
2020	64.50	27	1.75
2021	64.50	27	1.75
2022	64.50	27	1.75
2023	64.50	27	1.75
2024	64.50	27	1.75

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2015 Plan – Assumptions

- *Cane Run 7 Long-Term Service Agreement (LTSA)*
  - *CR7 LTSA cost is $771 per hour or $22,330/start ($2015), whichever is greater*
- *Cane Run 7 COD is 5/1/2015*

Cane Run 7 Commissioning Events

Event	Event Start Date 5/1/2015 CR7 COD Assumption	Notes
Transmission Outage (45 Days); CR6 Unavailable	9/15/2014-10/1/2014	Start date is dependent on forecast of sustained milder temperatures.
November Load Limit (524 MW Total; CR7 - 116 MW; 2 of 3 CR Coal Units - 408 MW)	11/1/2014	
December Load Limit (617 MW Total; CR7 - 462 MW; 2 of 3 CR Coal Units - 155 MW)	12/1/2014	
January through COD Load Limit (846 MW Total; CR7 - 691 MW; 2 of 3 CR Coal Units - 155 MW)	1/1/2015	
CR6 Permanently Unavailable	3/1/2015	
Transmission Outage (31 Days)	3/1/2015	
Transmission Outage (3 Days)	4/1/2015-5/1/2015	MC and/or CR generation may be limited during 3-day outage depending on system load levels.
CR4-5 Permanently Unavailable	5/1/2015	
MC2 Outage	3/9/2015	
MC1 Outage	3/23/2015	
CR7 COD	5/1/2015	

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Maintenance in 2015 increases by 11 weeks

Maintenance-Weeks

	2015 Plan					2014 Plan					2015 Plan - 2014 Plan				
	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Brown 1	8	3	1	3	1	8	3	1	3	1	-	-	-	-	-
Brown 2	1	3	8	2	3	1	3	8	1	3	-	-	-	1	-
Brown 3	7	3	1	3	8	7	3	1	3	8	-	-	-	-	-
Ghent 1	9	3	3	4	3	8	4	2	4	2	1	(1)	1	-	1
Ghent 2	11	4	3	3	9	6	4	3	3	9	5	-	-	-	-
Ghent 3	4	4	3	8	5	5	2	3	8	5	(1)	2	-	-	-
Ghent 4	-	4	3	4	3	-	3	3	4	2	-	1	-	-	1
Green River 3	1	-	-	-	-	-	-	-	-	-	1	-	-	-	-
Green River 4	2	1	-	-	-	-	-	-	-	-	2	1	-	-	-
Cane Run 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cane Run 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cane Run 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mill Creek 1	7	1	4	1	4	6	1	4	1	4	1	-	-	-	-
Mill Creek 2	7	4	1	4	1	6	4	1	4	1	1	-	-	-	-
Mill Creek 3	2	9	4	1	8	2	9	4	1	8	-	-	-	-	-
Mill Creek 4	2	4	1	4	1	1	4	1	4	1	1	-	-	-	-
Trimble County 1	5	2	9	2	5	5	2	9	2	5	-	-	-	-	-
Trimble County 2	3	5	3	9	5	5	5	5	9	5	(2)	-	(2)	-	-
Cane Run 7	2	2	2	2	4	-	-	2	-	8	2	2	-	2	(4)
Totals	**71**	**52**	**46**	**50**	**60**	**60**	**47**	**47**	**47**	**62**	**11**	**5**	**(1)**	**3**	**(2)**
MW-Maint Wks*	**28,126**	**22,814**	**19,207**	**23,574**	**27,566**	**23,956**	**20,253**	**19,847**	**21,947**	**29,166**	**4,169**	**2,561**	**(640)**	**1,628**	**(1,600)**

*Coal + CR7 Only

Notes:
Addition of outages for Green River 3 and 4 as a result of extension
Extension of existing outages at Ghent 2 (adding 5 weeks) and Ghent 1 (adding 1 week) to accommodate baghouse installation
Cane Run 7 maintenance schedule (placeholder that had been used before the 2014 Plan) updated to reflect maintenance needs for currently expected utilization

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With the exception of TC2, modeled EFOR assumptions are unchanged

	2015 Plan					2014 Plan					2015 Plan - 2014 Plan				
(%)	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Brown 1	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	0.0	0.0	0.0	0.0	0.0
Brown 2	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	0.0	0.0	0.0	0.0	0.0
Brown 3	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	0.0	0.0	0.0	0.0	0.0
Ghent 1	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	0.0	0.0	0.0	0.0	0.0
Ghent 2	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	0.0	0.0	0.0	0.0	0.0
Ghent 3	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	0.0	0.0	0.0	0.0	0.0
Ghent 4	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	0.0	0.0	0.0	0.0	0.0
Green River 3	8.1	8.4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Green River 4	8.1	8.4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Cane Run 4	8.1	N/A	N/A	N/A	N/A	8.1	N/A	N/A	N/A	N/A	0.0	N/A	N/A	N/A	N/A
Cane Run 5	8.1	N/A	N/A	N/A	N/A	8.1	N/A	N/A	N/A	N/A	0.0	N/A	N/A	N/A	N/A
Cane Run 6	8.1	N/A	N/A	N/A	N/A	8.1	N/A	N/A	N/A	N/A	0.0	N/A	N/A	N/A	N/A
Mill Creek 1	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	0.0	0.0	0.0	0.0	0.0
Mill Creek 2	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	0.0	0.0	0.0	0.0	0.0
Mill Creek 3	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	0.0	0.0	0.0	0.0	0.0
Mill Creek 4	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	0.0	0.0	0.0	0.0	0.0
Trimble County 1	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	0.0	0.0	0.0	0.0	0.0
Trimble County 2	6.0	6.0	6.0	6.0	6.0	5.6	5.1	5.1	5.1	5.1	0.4	0.9	0.9	0.9	0.9
Cane Run 7	7.0	6.0	5.0	4.0	4.0	7.0	6.0	5.0	4.0	4.0	0.0	0.0	0.0	0.0	0.0
Total EFOR	**6.1**	**5.8**	**5.6**	**5.5**	**5.5**	**6.0**	**5.6**	**5.5**	**5.4**	**5.4**	**0.1**	**0.2**	**0.1**	**0.1**	**0.1**
Total MOR	2.4	2.3	2.3	2.3	2.3	2.4	2.3	2.3	2.3	2.3	0.0	0.0	0.0	0.0	0.0
Total EUOR	8.5	8.1	7.9	7.8	7.8	8.4	7.9	7.8	7.7	7.7	0.1	0.2	0.1	0.1	0.1

Unit Rank by Operating Cost

	2015		2016		2017		2018		2019	
	2014 Plan	2015 Plan	2014 Plan	2015 Plan	2014 Plan	2015 Plan	2014 Plan	2015 Plan	2014 Plan	2015 Plan
Brown 1	14	16	14	14	14	14	14	14	15	14
Brown 2	13	15	13	13	13	13	13	13	13	13
Brown 3	15	17	15	15	15	15	15	15	14	15
Ghent 1	8	9	9	9	9	9	10	10	10	9
Ghent 2	4	3	3	6	3	7	4	9	2	4
Ghent 3	10	12	10	11	10	11	7	6	11	11
Ghent 4	12	11	11	10	12	10	12	11	12	10
Mill Creek 1	6	4	4	2	6	3	5	2	6	3
Mill Creek 2	5	6	6	3	5	4	6	3	7	5
Mill Creek 3	3	5	7	5	8	5	9	5	3	2
Mill Creek 4	9	10	8	7	7	8	8	7	9	7
Trimble County 1	2	7	2	4	2	2	2	4	5	6
Trimble County 2	1	1	1	1	1	1	1	1	1	1
Cane Run 7	11	14	12	12	11	12	11	12	8	12
OVEC	7	8	5	8	4	6	3	8	4	8
Green River 3		13								
Green River 4		2								

Cane run 4-6 and Green River 3-4 are excluded in years with partial operation.

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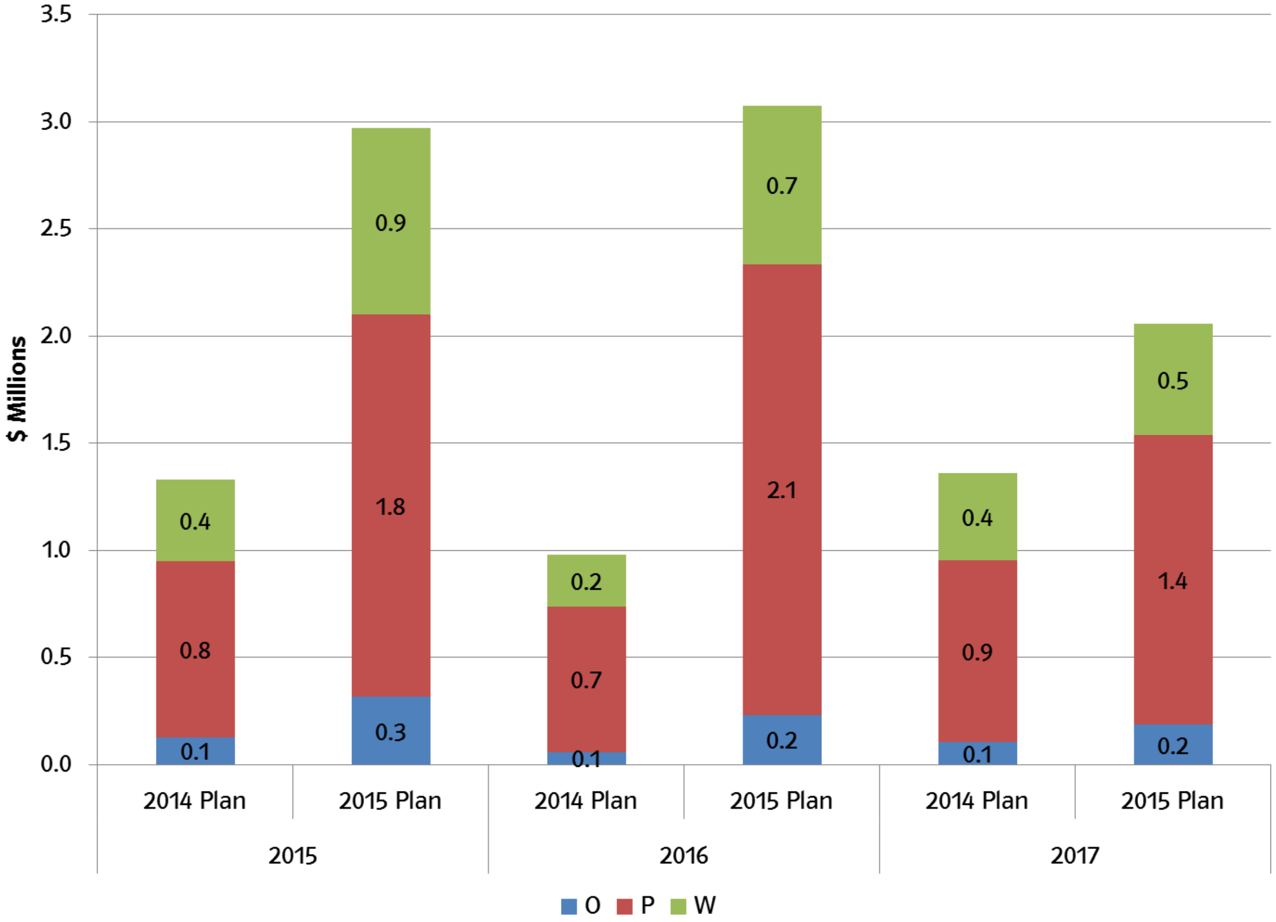
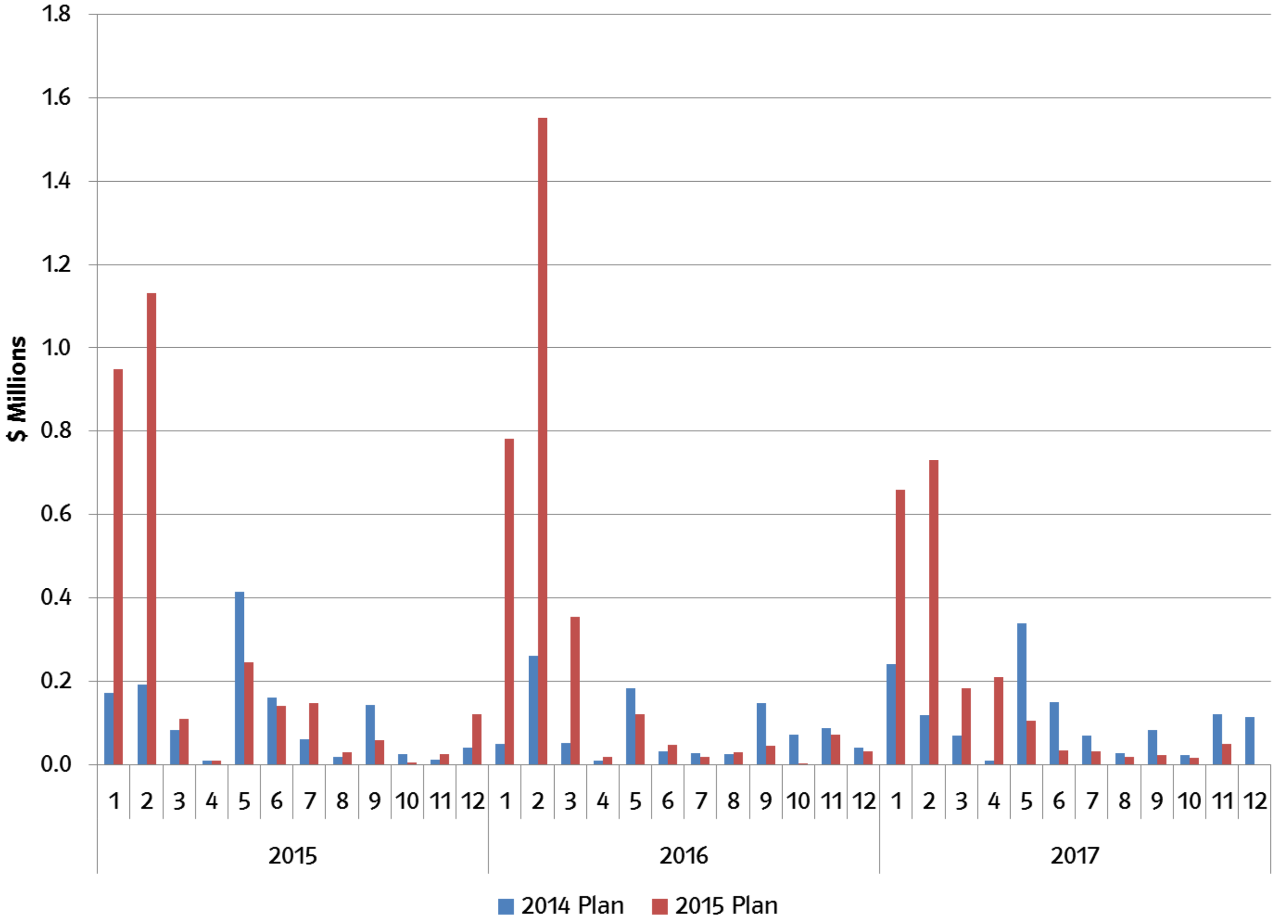
OSS Contribution by Peak Type



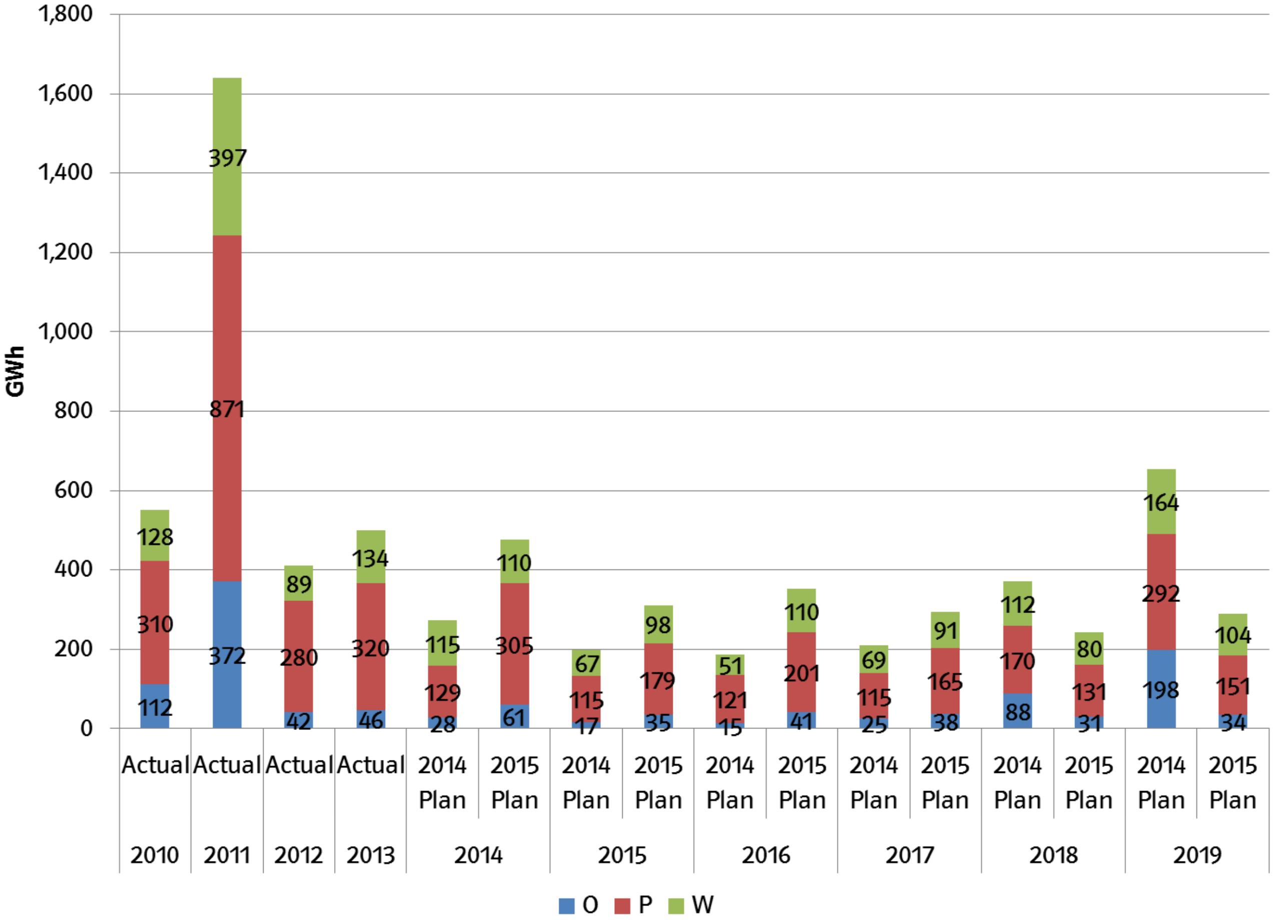
PPL companies

Increase in OSS contribution is concentrated mostly in January and February



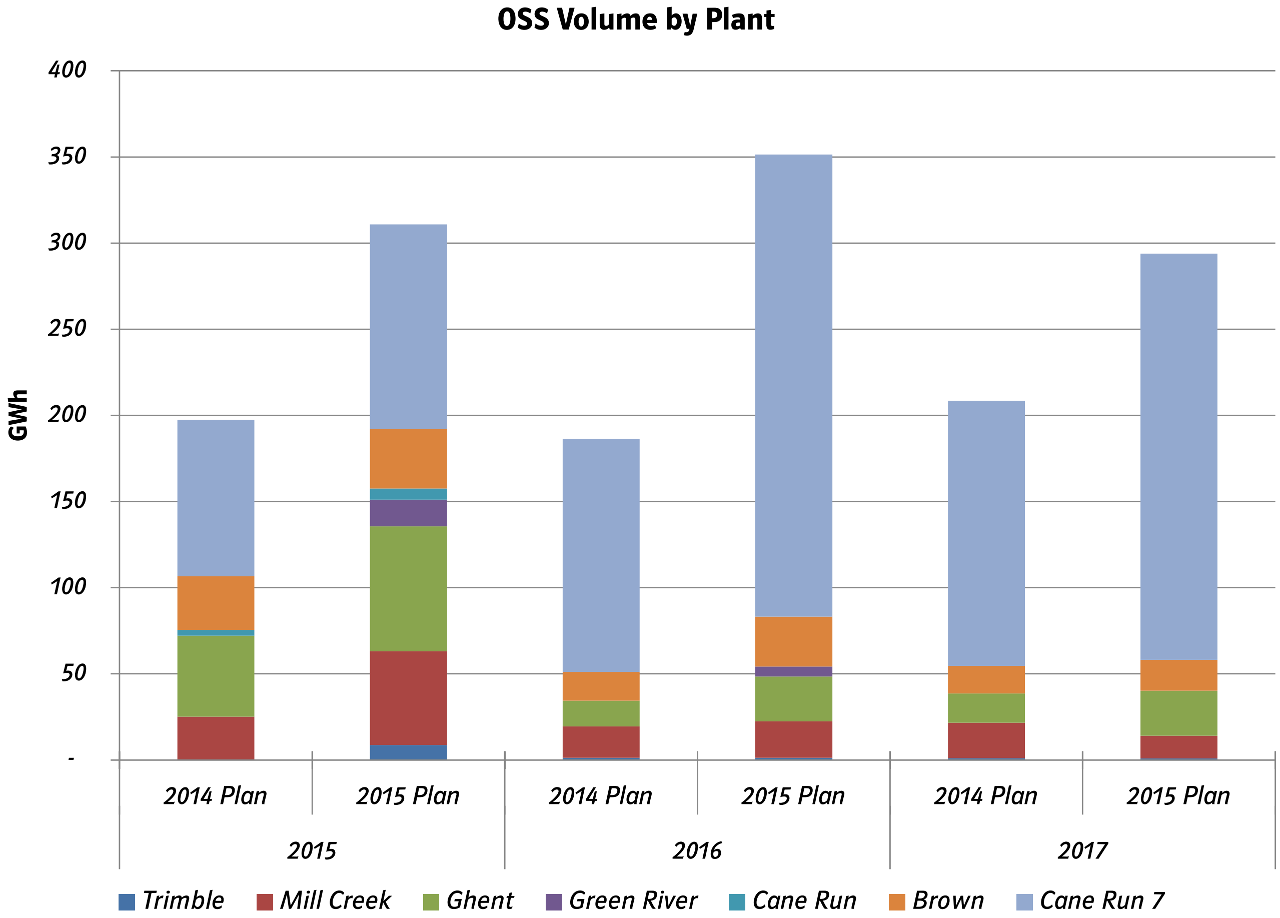
LG&E KU
PPL companies

OSS volumes slightly higher in 2015



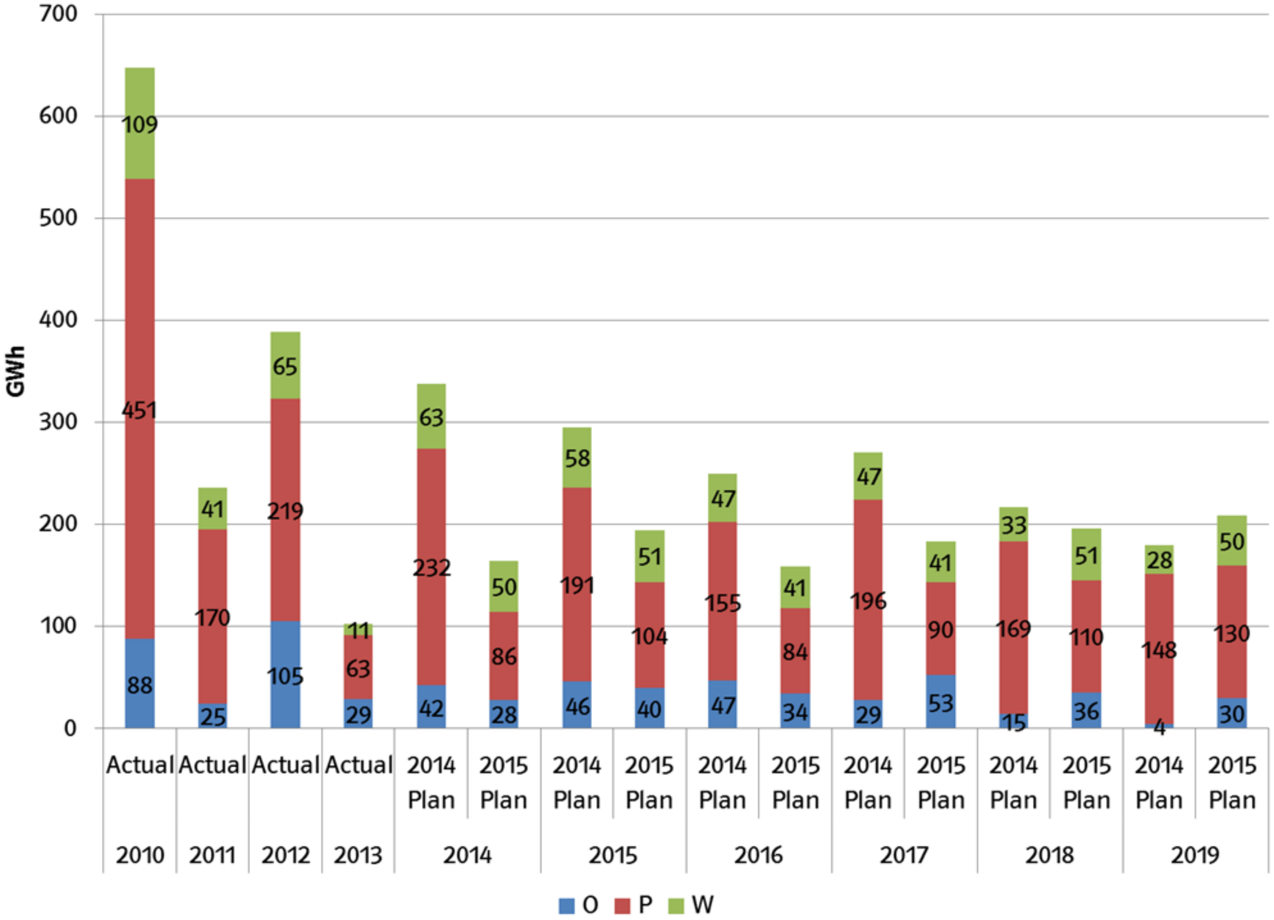
LG&E KU
PPL companies

Majority of OSS volumes attributed to Cane Run 7



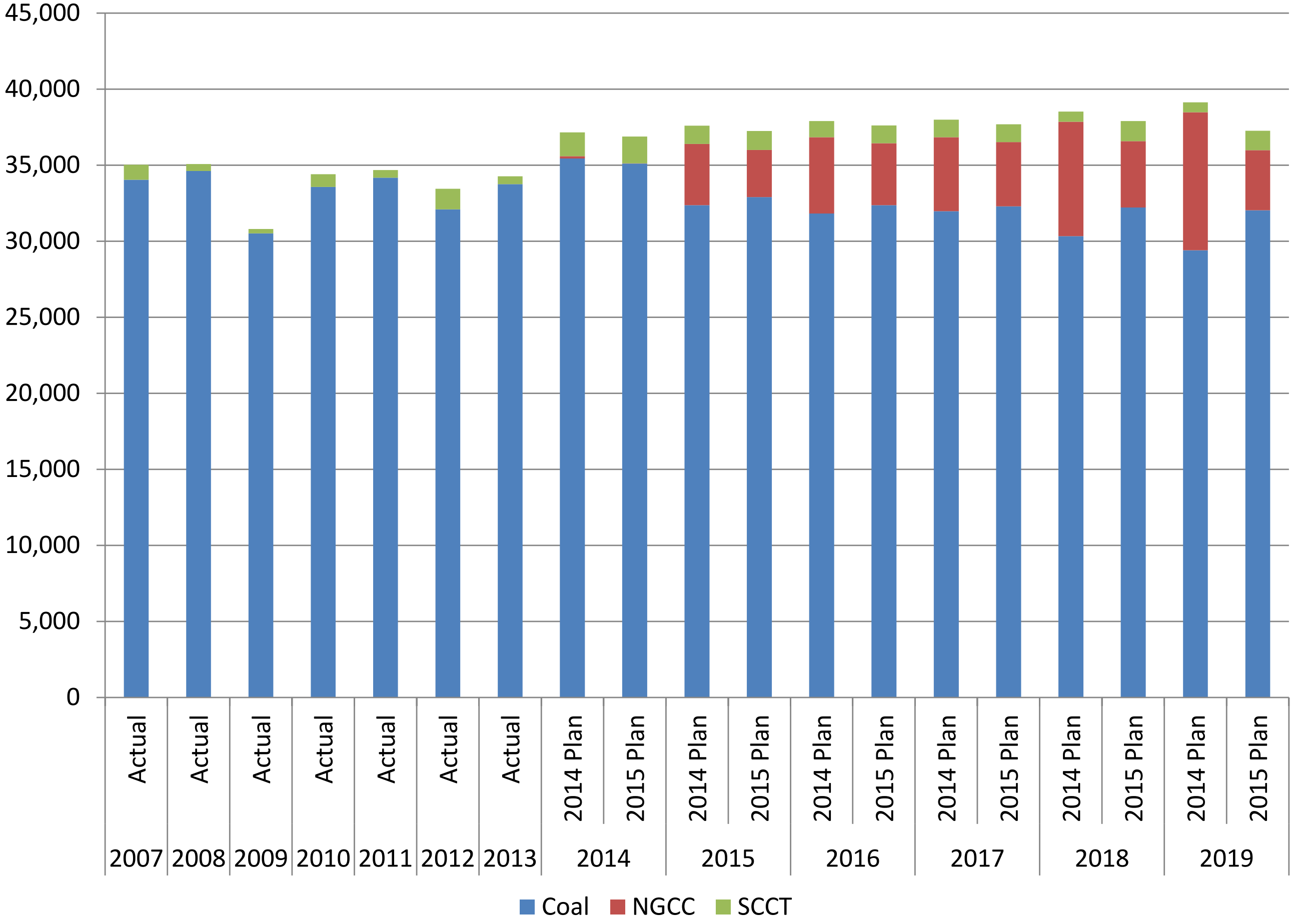
PPL companies

Economy purchases lower (and more in line with recent history) due to reduced purchase limits



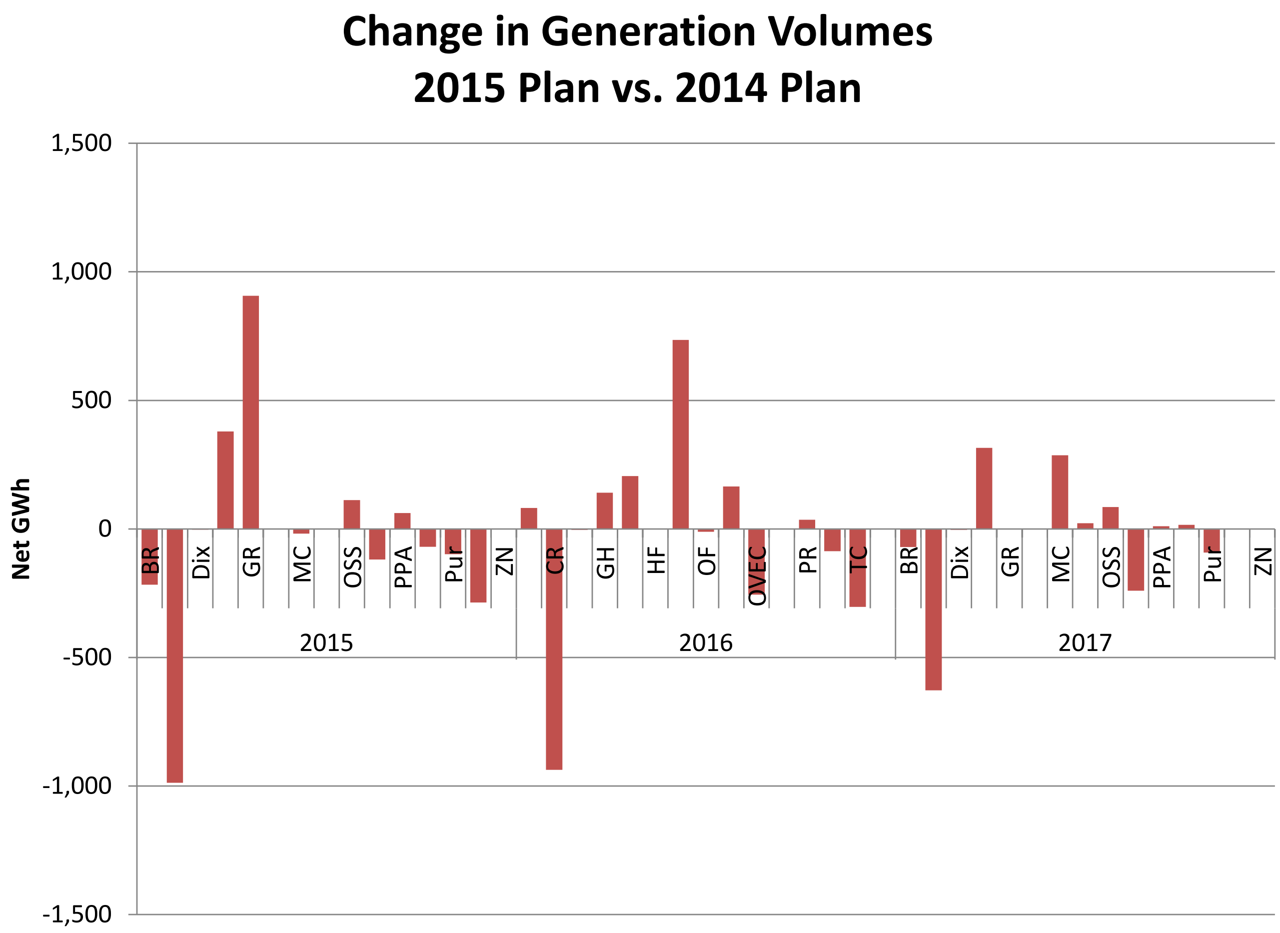
PPL companies

Total coal and gas generation remains mostly unchanged in 2015 Plan



2014: 6 + 6

In 2015 Plan, generation shifts from Cane Run 7 to coal units



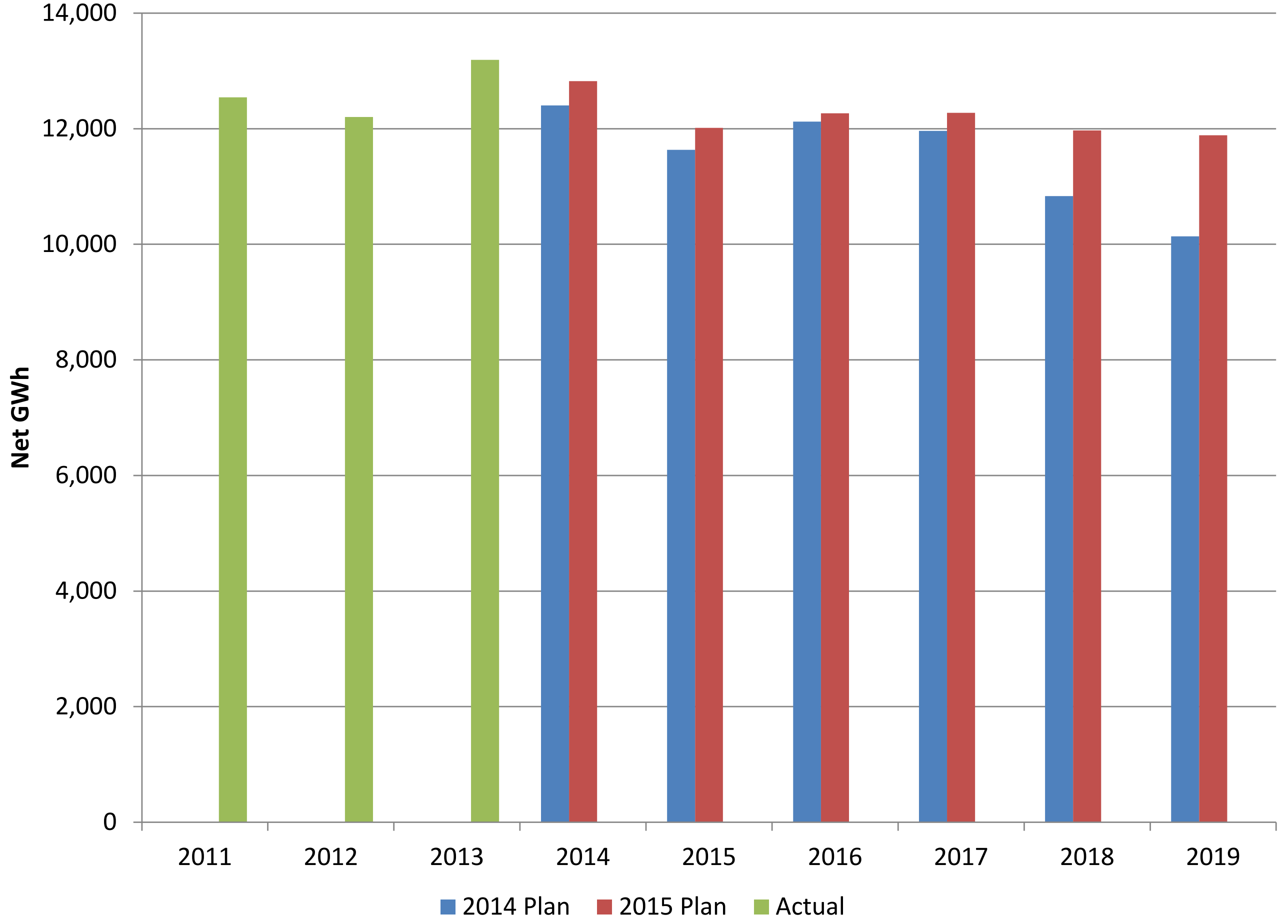
LG&E KU
PPL companies

Trimble coal generation decreases in 2015 Plan primarily due to higher variable O&M costs

2014: 6 + 6

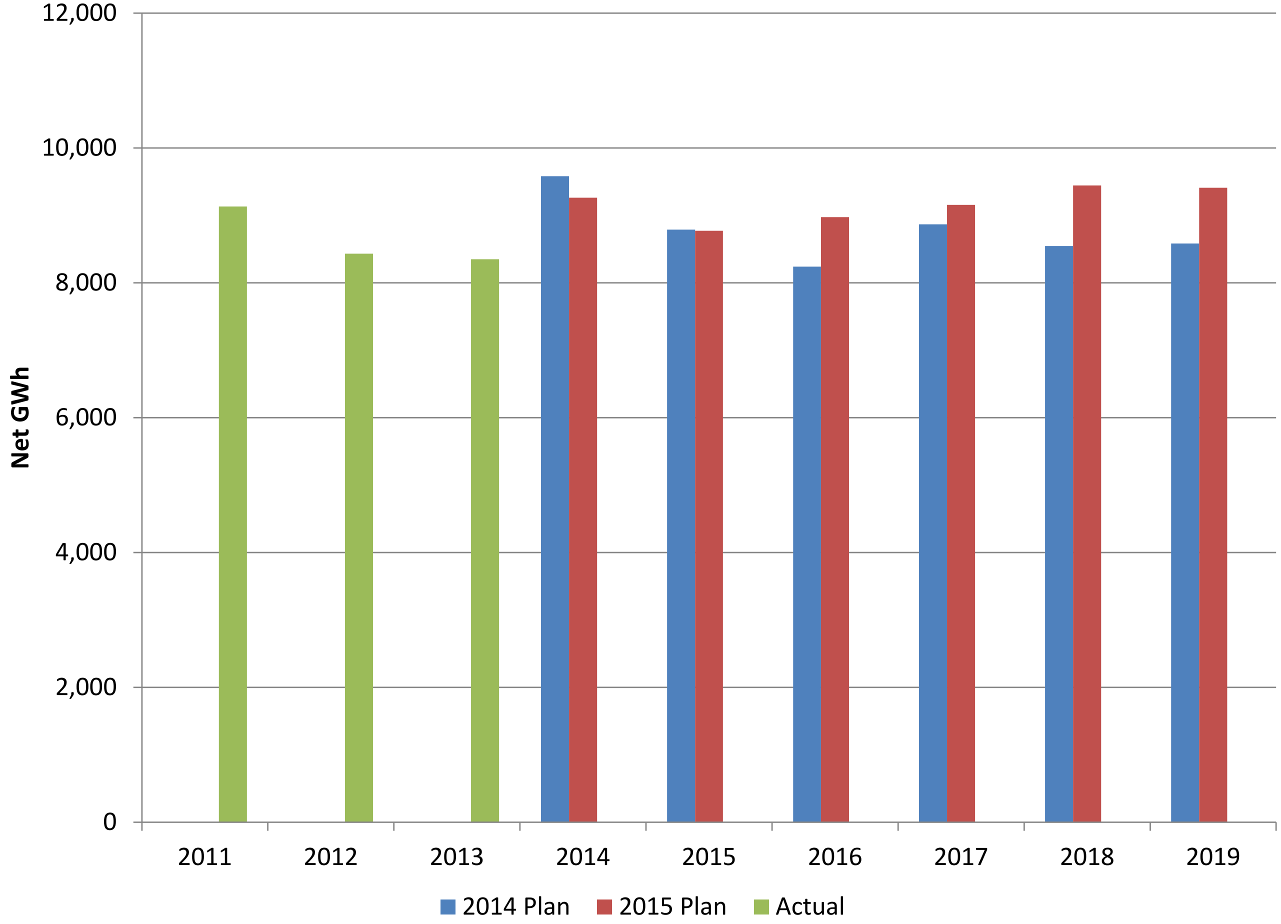
PPL companies

Ghent generation in the 2015 Plan increases mostly due to lower coal prices and increased SCR operation



2014: 6 + 6

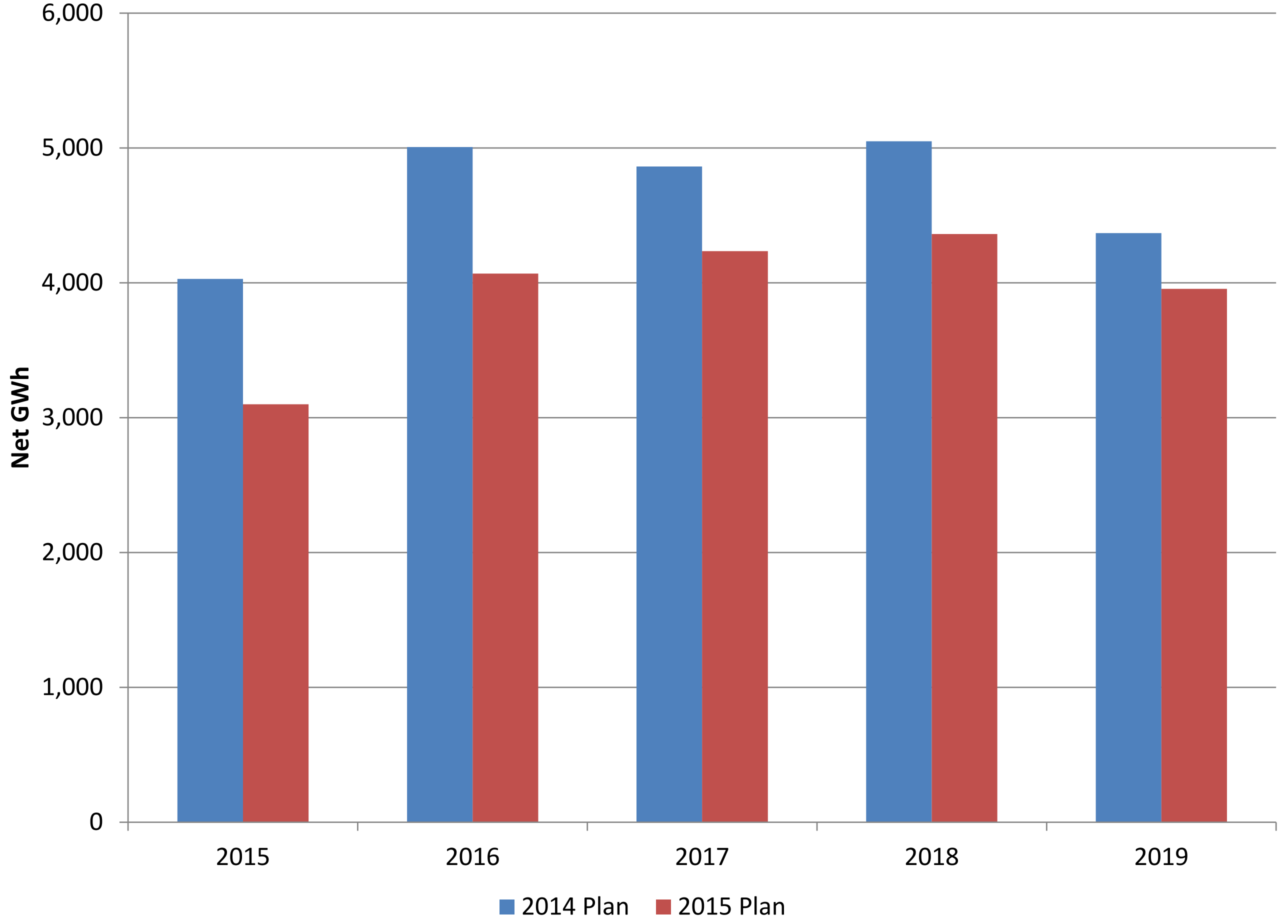
Mill Creek generation is higher in 2016-2019 due to lower variable O&M costs



2014: 6 + 6

PPL companies

Generation shifts from Cane Run 7 to coal units due to lower coal variable O&M, additional maintenance weeks for Cane Run 7, and the Green River 3-4 extension



2014: 6 + 6

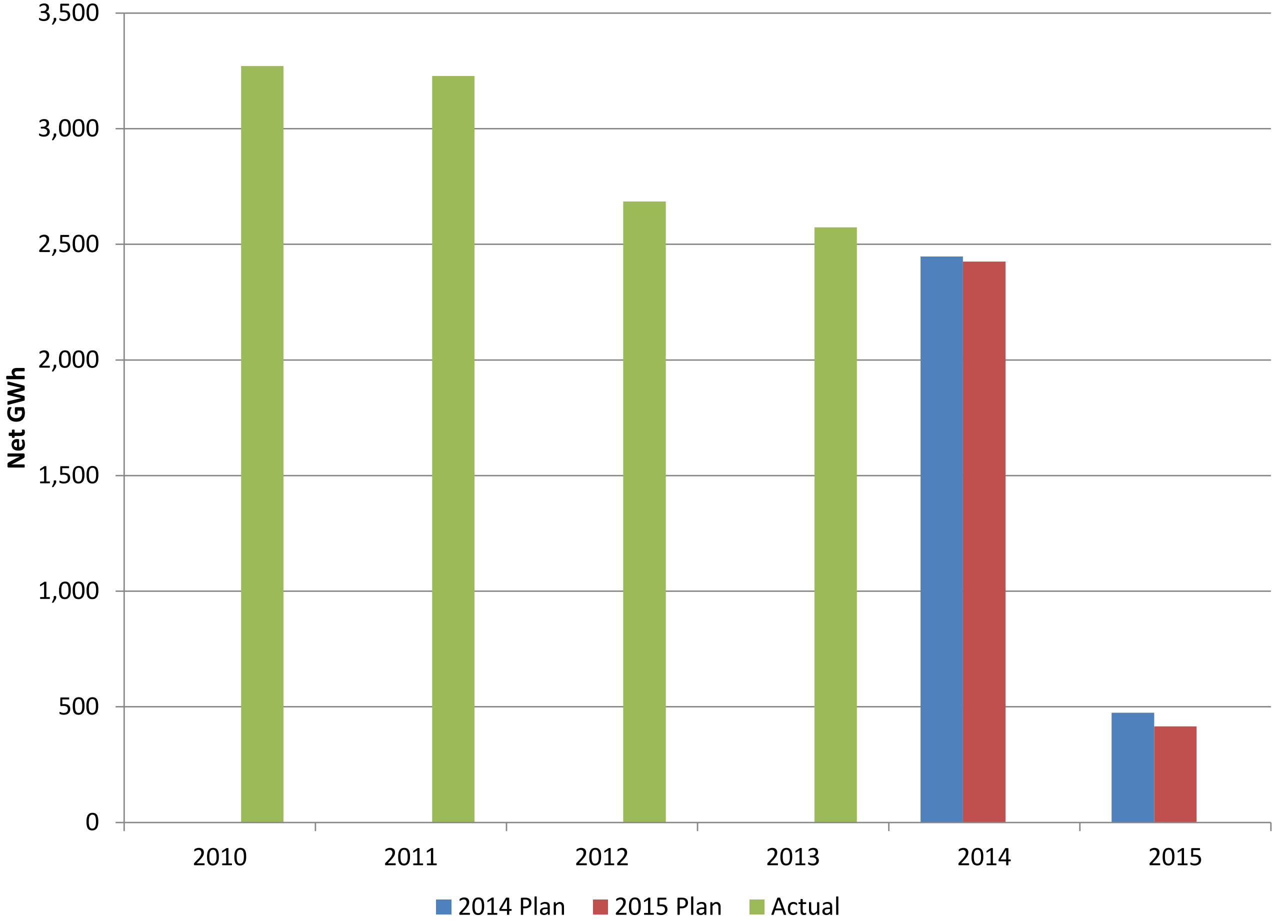
In the 2015 Plan, generation shifts from Cane Run 7 to coal

Cane Run 7 Capacity Factor Changes (%)

	2015	2016
2014 Plan	**88**	**86**
Key Changes:		
SCR Operation	-6	-3
Coal Variable O&M	-4	-3
Cane Run 7 Heat Rate	-4	-4
Electricity and Gas Prices	-3	7
Coal Prices	-1	-9
Planned Maintenance	-3	-3
Green River Extension	-3	-1
2015 Plan	**63**	**71**

LG&E KU
PPL companies

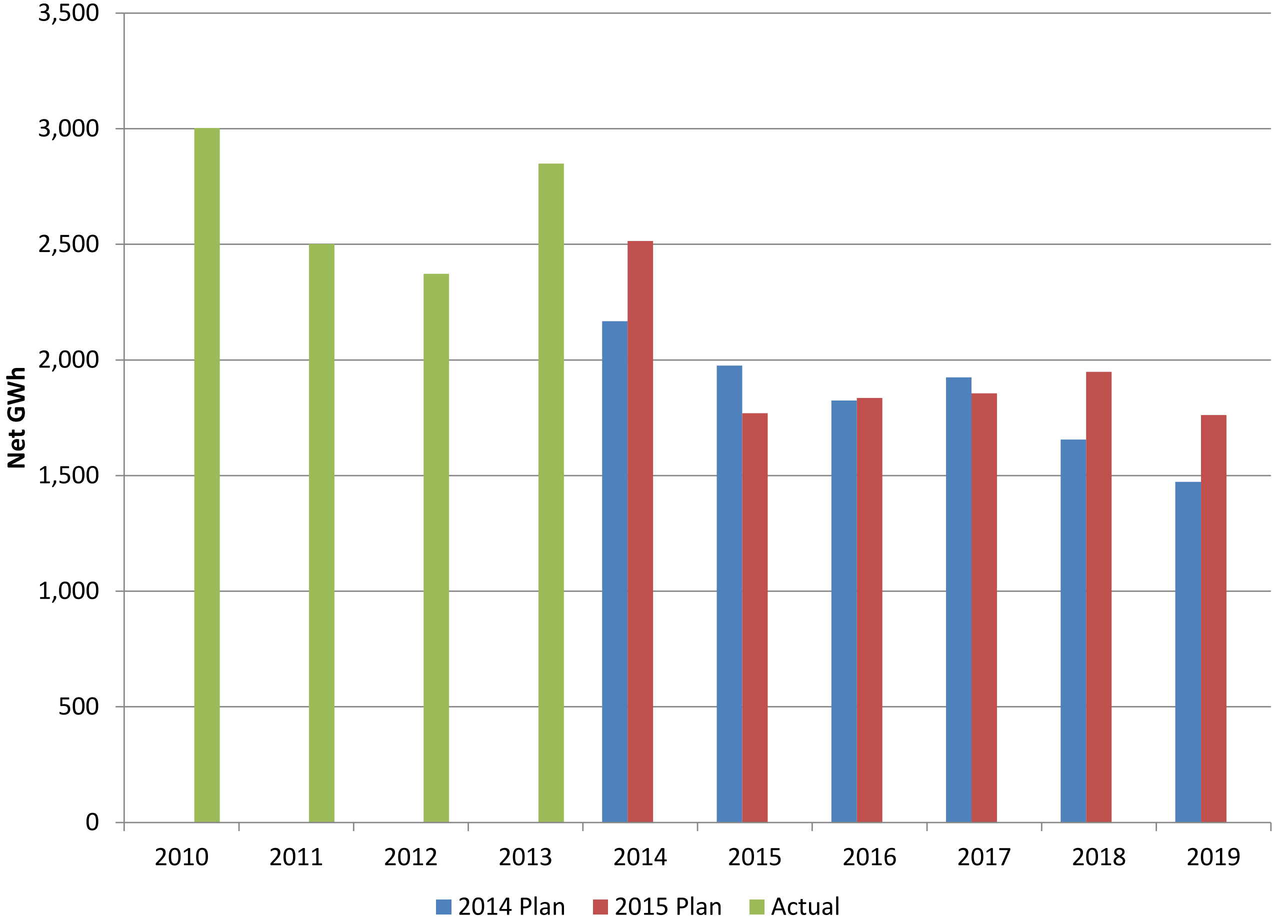
Cane Run coal generation is mostly unchanged



2013: 7 + 5

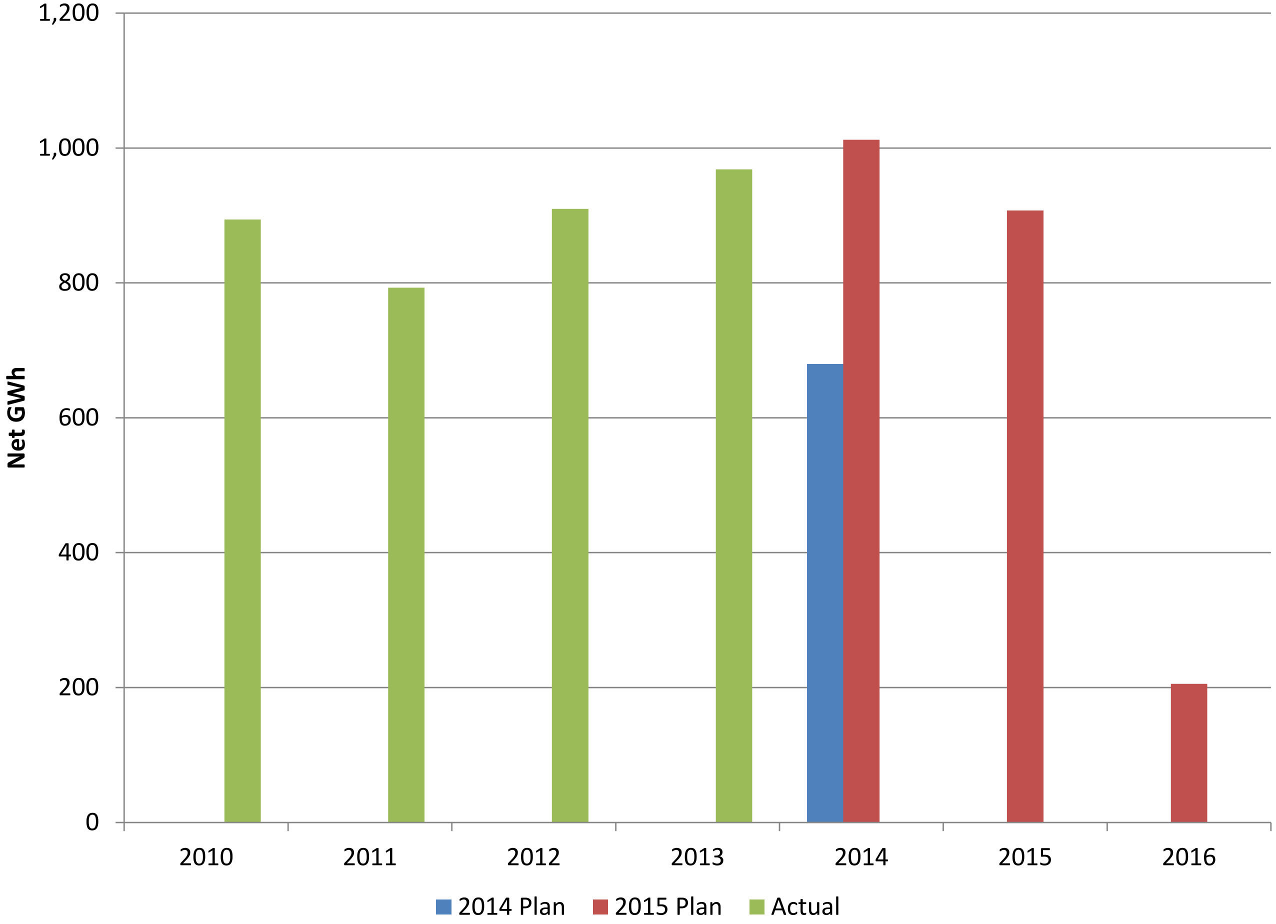
LG&E KU
PPL companies

Brown coal generation increases beyond 2017 due to the deferral of Green River 5



2013: 6 + 6

Green River generation increases in 2015 Plan due to its extended operation



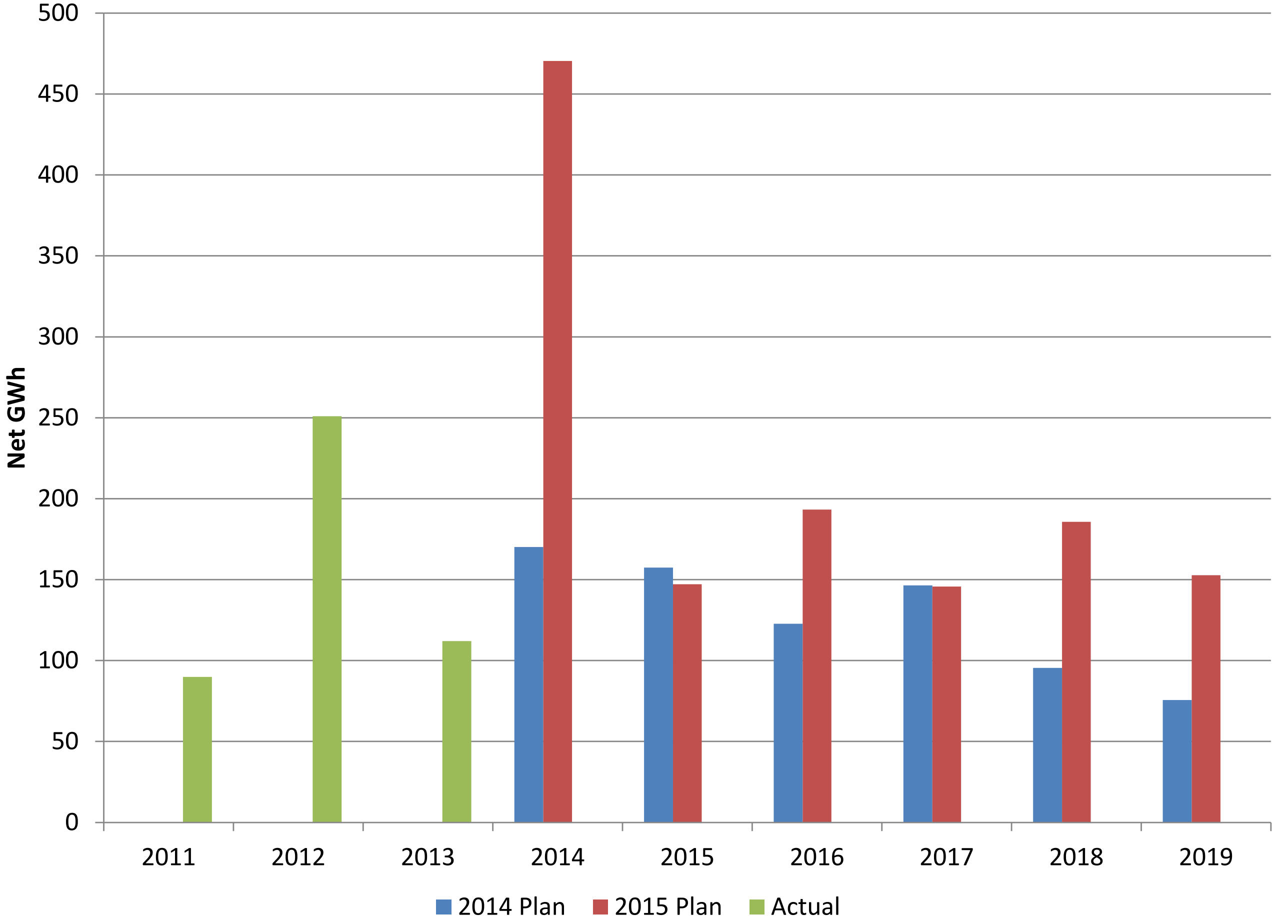
2014: 6 + 6

Trimble CT generation increases beyond 2017 due to the deferral of Green River 5

2014: 6 + 6

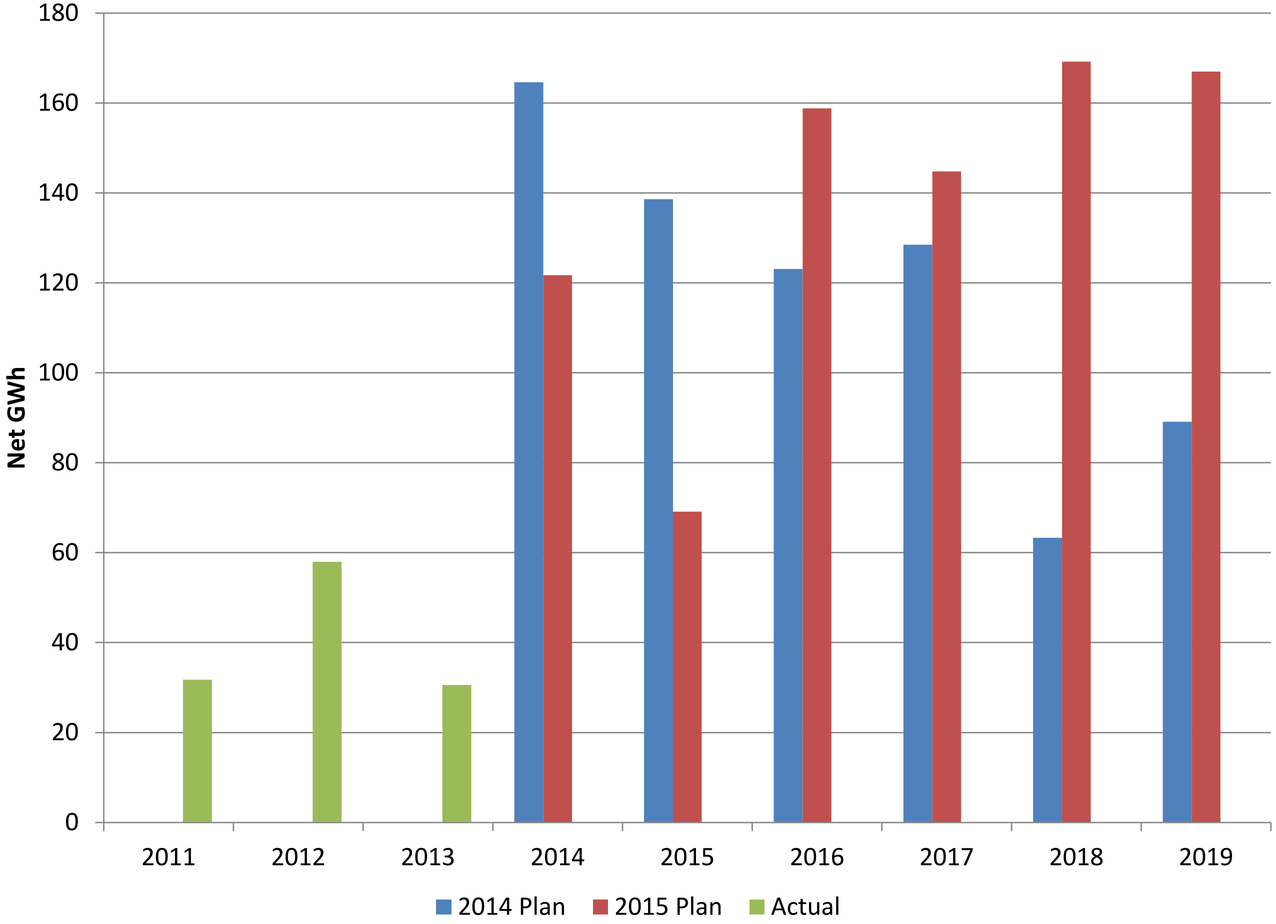
LG&E KU
PPL companies

Brown CT generation increases beyond 2015 due primarily to lower gas prices and the deferral of Green River 5



2014: 6 + 6

2015 Plan assumes Paddy's Run units available year-round beginning 1/1/2016 (pending completion of gas pipeline project)



2014: 6 + 6

PPL companies

Variable O&M costs drive generation differences between 2014 and 2015 Plans

Total VO&M ($/MWh)	2015			2016			2017			2018		
	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff
Brown 1	2.14	3.01	0.86	2.65	2.82	0.17	2.47	2.59	0.12	2.55	2.93	0.38
Brown 2	1.77	2.75	0.98	2.26	2.76	0.50	2.25	2.78	0.54	2.32	2.90	0.58
Brown 3	5.93	3.32	(2.61)	7.58	3.66	(3.92)	7.83	3.58	(4.25)	8.04	4.05	(3.98)
Cane Run 4	4.39	4.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cane Run 5	4.09	4.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cane Run 6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ghent 1	3.75	3.24	(0.51)	3.93	3.35	(0.59)	4.34	3.63	(0.71)	4.67	3.94	(0.74)
Ghent 2	1.94	2.31	0.37	2.06	2.73	0.67	2.37	2.92	0.54	2.62	3.23	0.61
Ghent 3	3.56	3.34	(0.22)	3.83	3.44	(0.40)	4.37	3.77	(0.61)	4.93	4.11	(0.82)
Ghent 4	4.14	3.37	(0.76)	4.13	3.44	(0.69)	5.05	3.82	(1.23)	5.76	4.23	(1.54)
Mill Creek 1	3.17	1.56	(1.61)	3.89	1.65	(2.24)	3.85	1.68	(2.18)	3.90	1.74	(2.16)
Mill Creek 2	2.94	1.58	(1.37)	3.88	1.68	(2.20)	3.61	1.70	(1.91)	3.90	1.77	(2.14)
Mill Creek 3	1.59	1.41	(0.17)	5.19	2.51	(2.67)	5.06	2.45	(2.61)	5.09	2.52	(2.58)
Mill Creek 4	4.22	2.28	(1.94)	4.53	2.39	(2.14)	4.07	2.45	(1.62)	4.37	2.52	(1.86)
Trimble 1	2.11	2.63	0.52	2.83	2.74	(0.09)	3.24	2.89	(0.35)	3.08	3.17	0.08
Trimble 2	1.73	2.16	0.43	1.79	2.25	0.46	1.81	2.39	0.58	1.99	2.66	0.67

PPL companies

FGD O&M for all units reflects the inclusion of variable landfill costs

FGD	2015			2016			2017			2018		
($/MWh)	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff
Brown 1	0.88	1.47	0.58	0.94	1.31	0.37	1.01	1.21	0.20	1.03	1.46	0.43
Brown 2	0.85	1.42	0.57	0.92	1.43	0.50	1.02	1.48	0.47	1.04	1.56	0.53
Brown 3	1.14	1.51	0.37	1.18	1.63	0.44	1.18	1.51	0.32	1.21	1.97	0.77
Cane Run 4	4.39	4.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cane Run 5	4.09	4.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cane Run 6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ghent 1	1.03	1.04	0.01	1.09	1.08	(0.00)	1.30	1.26	(0.04)	1.47	1.42	(0.06)
Ghent 2	1.04	1.28	0.24	1.09	1.50	0.42	1.30	1.67	0.37	1.47	1.86	0.38
Ghent 3	1.03	1.04	0.01	1.09	1.07	(0.01)	1.30	1.25	(0.05)	1.46	1.37	(0.09)
Ghent 4	1.03	1.04	0.01	1.08	1.10	0.01	1.29	1.24	(0.05)	1.46	1.38	(0.08)
Mill Creek 1	0.71	0.78	0.07	0.74	0.83	0.09	0.74	0.83	0.09	0.75	0.86	0.11
Mill Creek 2	0.72	0.78	0.06	0.75	0.83	0.08	0.72	0.83	0.11	0.77	0.86	0.10
Mill Creek 3	0.99	1.01	0.02	1.11	0.96	(0.15)	1.09	0.83	(0.26)	1.09	0.86	(0.23)
Mill Creek 4	0.73	0.79	0.06	0.76	0.83	0.07	0.71	0.82	0.11	0.76	0.86	0.10
Trimble 1	0.58	0.56	(0.01)	0.59	0.58	(0.02)	0.62	0.65	0.03	0.63	0.85	0.22
Trimble 2	0.39	0.40	0.00	0.41	0.40	(0.00)	0.42	0.46	0.04	0.43	0.68	0.25

PPL companies

SCR O&M is mostly unchanged

SCR	2015			2016			2017			2018		
($/MWh)	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff
Brown 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Brown 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Brown 3	0.54	0.43	(0.11)	0.54	0.45	(0.09)	0.54	0.48	(0.06)	0.55	0.46	(0.09)
Cane Run 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cane Run 5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cane Run 6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ghent 1	0.53	0.41	(0.12)	0.51	0.43	(0.09)	0.52	0.45	(0.07)	0.53	0.44	(0.09)
Ghent 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ghent 3	0.53	0.41	(0.12)	0.51	0.43	(0.09)	0.52	0.45	(0.07)	0.53	0.44	(0.09)
Ghent 4	0.53	0.41	(0.12)	0.51	0.43	(0.09)	0.52	0.45	(0.07)	0.53	0.44	(0.09)
Mill Creek 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mill Creek 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mill Creek 3	0.47	0.40	(0.07)	0.45	0.43	(0.02)	0.46	0.45	(0.01)	0.47	0.44	(0.04)
Mill Creek 4	0.51	0.44	(0.07)	0.50	0.46	(0.03)	0.50	0.49	(0.02)	0.51	0.47	(0.04)
Trimble 1	0.42	0.30	(0.12)	0.41	0.31	(0.09)	0.41	0.33	(0.08)	0.42	0.32	(0.10)
Trimble 2	0.39	0.34	(0.06)	0.39	0.36	(0.03)	0.39	0.38	(0.01)	0.40	0.37	(0.03)

PPL companies

SO$_3$ O&M is lower for Mill Creek and Ghent

SO3	2015			2016			2017			2018		
($/MWh)	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff
Brown 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Brown 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Brown 3	0.32	0.41	0.09	0.32	0.43	0.11	0.32	0.44	0.12	0.33	0.46	0.13
Cane Run 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cane Run 5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cane Run 6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ghent 1	1.42	1.07	(0.35)	1.52	1.10	(0.42)	1.65	1.16	(0.49)	1.76	1.26	(0.50)
Ghent 2	0.19	0.48	0.30	0.21	0.53	0.33	0.23	0.54	0.31	0.25	0.60	0.35
Ghent 3	1.24	1.14	(0.10)	1.38	1.16	(0.22)	1.59	1.25	(0.35)	1.84	1.39	(0.45)
Ghent 4	1.71	1.20	(0.50)	1.67	1.20	(0.48)	2.16	1.34	(0.82)	2.53	1.51	(1.02)
Mill Creek 1	0.91	0.20	(0.71)	1.31	0.21	(1.10)	1.38	0.22	(1.15)	1.46	0.24	(1.22)
Mill Creek 2	0.87	0.20	(0.66)	1.31	0.22	(1.09)	1.38	0.23	(1.15)	1.46	0.24	(1.21)
Mill Creek 3	0.12	0.00	(0.12)	1.32	0.53	(0.79)	1.43	0.55	(0.87)	1.51	0.58	(0.92)
Mill Creek 4	1.04	0.48	(0.56)	1.10	0.51	(0.59)	1.16	0.53	(0.62)	1.22	0.56	(0.66)
Trimble 1	0.47	1.07	0.60	0.50	1.12	0.62	0.52	1.16	0.64	0.55	1.21	0.66
Trimble 2	0.30	0.90	0.60	0.31	0.94	0.63	0.33	0.98	0.65	0.35	1.02	0.67

Variable O&M for mercury control is generally lower

Mercury	2015			2016			2017			2018		
($/MWh)	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff	2014 Plan	2015 Plan	Diff
Brown 1	1.26	1.54	0.28	1.71	1.51	(0.20)	1.46	1.38	(0.08)	1.52	1.47	(0.05)
Brown 2	0.92	1.33	0.41	1.34	1.33	(0.01)	1.23	1.30	0.07	1.28	1.34	0.06
Brown 3	3.93	0.98	(2.95)	5.54	1.15	(4.39)	5.79	1.15	(4.64)	5.96	1.16	(4.80)
Cane Run 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cane Run 5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cane Run 6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ghent 1	0.78	0.73	(0.05)	0.81	0.73	(0.08)	0.87	0.76	(0.10)	0.92	0.83	(0.09)
Ghent 2	0.72	0.55	(0.17)	0.76	0.69	(0.07)	0.84	0.70	(0.14)	0.90	0.77	(0.13)
Ghent 3	0.77	0.76	(0.01)	0.85	0.77	(0.08)	0.96	0.82	(0.14)	1.11	0.91	(0.19)
Ghent 4	0.88	0.72	(0.15)	0.86	0.71	(0.14)	1.08	0.79	(0.29)	1.25	0.90	(0.35)
Mill Creek 1	1.54	0.58	(0.96)	1.84	0.61	(1.24)	1.73	0.62	(1.11)	1.70	0.64	(1.06)
Mill Creek 2	1.36	0.59	(0.77)	1.82	0.63	(1.19)	1.51	0.64	(0.87)	1.68	0.66	(1.02)
Mill Creek 3	0.00	0.00	0.00	2.32	0.60	(1.71)	2.08	0.62	(1.46)	2.02	0.63	(1.39)
Mill Creek 4	1.94	0.57	(1.37)	2.18	0.59	(1.58)	1.70	0.61	(1.09)	1.89	0.62	(1.27)
Trimble 1	0.65	0.70	0.05	1.33	0.73	(0.60)	1.69	0.75	(0.94)	1.48	0.78	(0.70)
Trimble 2	0.65	0.53	(0.12)	0.69	0.55	(0.14)	0.67	0.57	(0.10)	0.82	0.59	(0.23)

PPL companies

2015 heat rate assumptions are mostly unchanged in 2015 Plan

	2014 Plan	2015 Plan	Difference (2015 Plan vs 2014 Plan)	Percent Change
CR4	11,380	11,380	0	0.0%
CR5	10,380	10,380	0	0.0%
CR6	10,070	10,070	0	0.0%
MC1	10,490	10,340	-150	-1.4%
MC2	10,420	10,470	50	0.5%
MC3	10,530	10,530	0	0.0%
MC4	10,730	10,740	10	0.1%
TC1	10,470	10,550	80	0.8%
TC2	9,230	9,250	20	0.2%
BR1	10,560	10,370	-190	-1.8%
BR2	10,270	10,280	10	0.1%
BR3	10,800	10,840	40	0.4%
GH1 (Before Baghouse)	10,810	10,810	0	0.0%
GH1 (After Baghouse)	10,950	10,860	-90	-0.8%
GH2 (Before Baghouse)	10,620	10,620	0	0.0%
GH2 (After Baghouse)	10,810	10,660	-150	-1.4%
GH3 (Before Baghouse)	10,840	10,940	100	0.9%
GH3 (After Baghouse)	10,970	11,030	60	0.5%
GH4 (Before Baghouse)	10,860	10,860	0	0.0%
GH4 (After Baghouse)	11,000	10,950	-50	-0.5%
GR3	13,260	13,380	120	0.9%
GR4	10,650	11,180	530	5.0%
CR7	6,890	6,840	-50	-0.7%

Notes:
Values shown represent summer heat rates at maximum load.
Baghouse derate projections for Ghent units decreased from 6, 9, 6, and 6 MW to 2, 2, 4, and 4 MW respectively. These changes led to an improved heat rate for all Ghent units (roughly 0.2% per MW).

SCCT operation expected to remain high

CT Generation *(GWh)*

	ACTUAL				(6+6)	2015 Plan				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
BR5, 8-11	34	16	24	14	101	19	37	25	38	21
BR6, 7	95	62	223	93	364	128	156	121	148	132
PR13	15	31	56	29	119	69	159	145	169	167
TC5-10	682	376	1,034	366	1,168	968	750	792	871	925
	826	**485**	**1,337**	**502**	**1,753**	**1,185**	**1,102**	**1,082**	**1,226**	**1,245**

2014 Plan				
1,199	**811**	**877**	**743**	**654**

CT Starts *(# starts)*

	ACTUAL				(6+6)	2015 Plan				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
BR5, 8-11	137	88	103	78	202	102	153	150	163	141
BR6, 7	139	110	185	119	220	172	174	161	180	194
PR13	18	49	68	28	92	94	219	218	259	236
TC5-10	779	509	626	499	945	978	748	773	918	888
	1,073	**756**	**982**	**724**	**1,459**	**1,346**	**1,294**	**1,302**	**1,520**	**1,459**

2014 Plan				
1,532	**1,028**	**1,057**	**951**	**910**

CT Generation (GWh)/Start

	ACTUAL				(6+6)	2015 Plan				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
BR5, 8-11	0.2	0.2	0.2	0.2	0.5	0.2	0.2	0.2	0.2	0.2
BR6, 7	0.7	0.6	1.2	0.8	1.7	0.7	0.9	0.8	0.8	0.7
PR13	0.8	0.6	0.8	1.0	1.3	0.7	0.7	0.7	0.7	0.7
TC5-10	0.9	0.7	1.7	0.7	1.2	1.0	1.0	1.0	0.9	1.0
	0.8	**0.6**	**1.4**	**0.7**	**1.2**	**0.9**	**0.9**	**0.8**	**0.8**	**0.9**

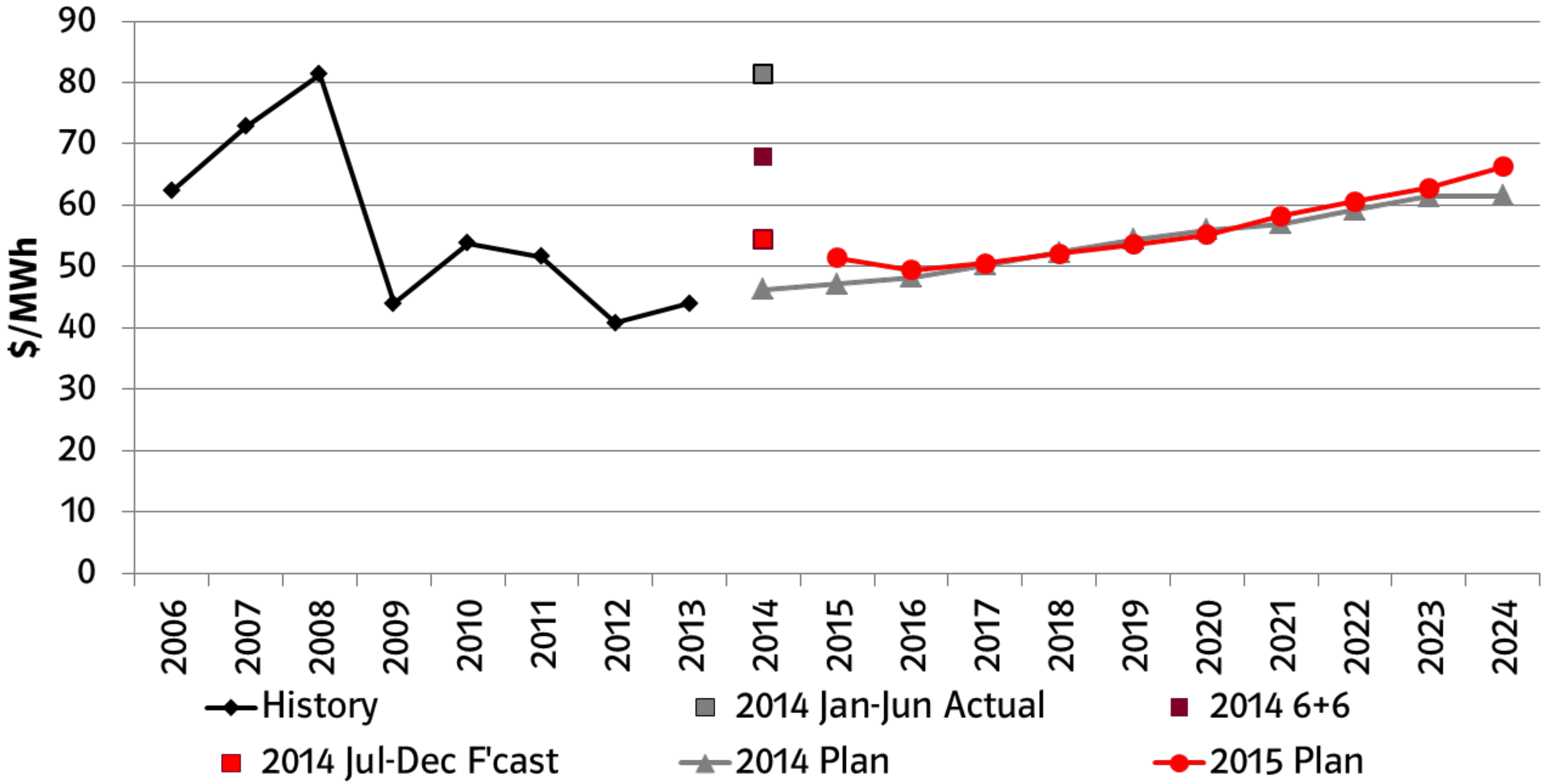
2014 Plan				
0.8	**0.8**	**0.8**	**0.8**	**0.7**

CT Run Hours/Start

	ACTUAL				(6+6)	2015 Plan				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
BR5, 8-11	4.6	4.3	4.3	3.8	9.4	3.7	4.8	3.4	4.5	3.1
BR6, 7	8.7	7.0	10.1	8.0	16.9	7.3	8.1	7.3	7.7	6.8
PR13	5.9	5.4	6.9	7.9	9.6	5.5	5.2	4.7	4.7	5.2
TC5-10	7.8	7.3	11.9	7.7	11.5	7.9	7.8	7.8	7.4	8.4
	7.4	**6.8**	**10.4**	**7.3**	**11.9**	**7.3**	**7.1**	**6.7**	**6.7**	**7.1**

2014 Plan				
6.8	**6.8**	**7.0**	**6.8**	**6.0**

Electricity: PJM-West peak (5x16)



- *2015-2017 prices are ICE forward market prices as of June 23, 2014.*
- *2018-2019 prices are interpolated.*
- *Long-term prices from 2020 are modeled in AURORA.*

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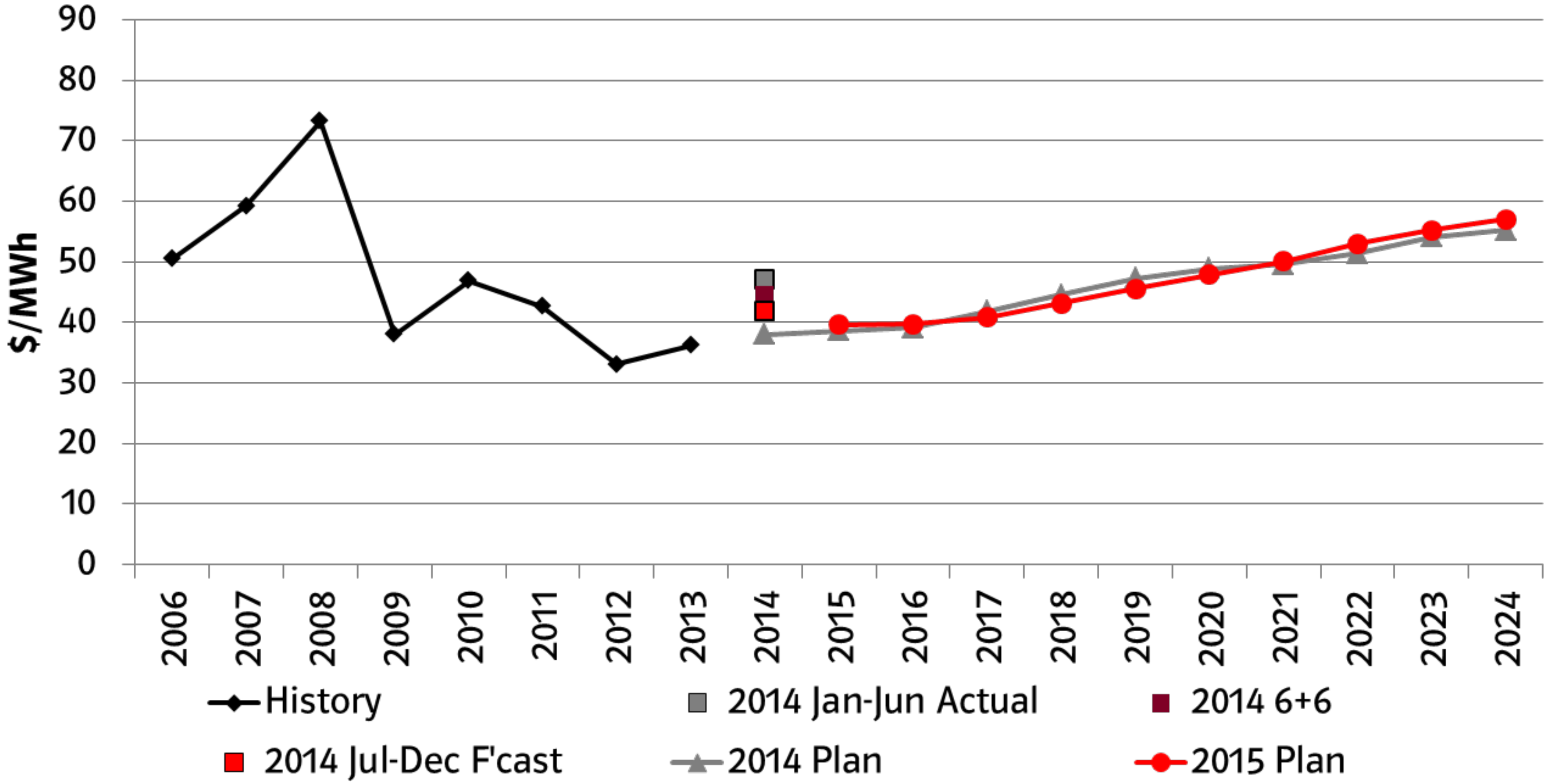
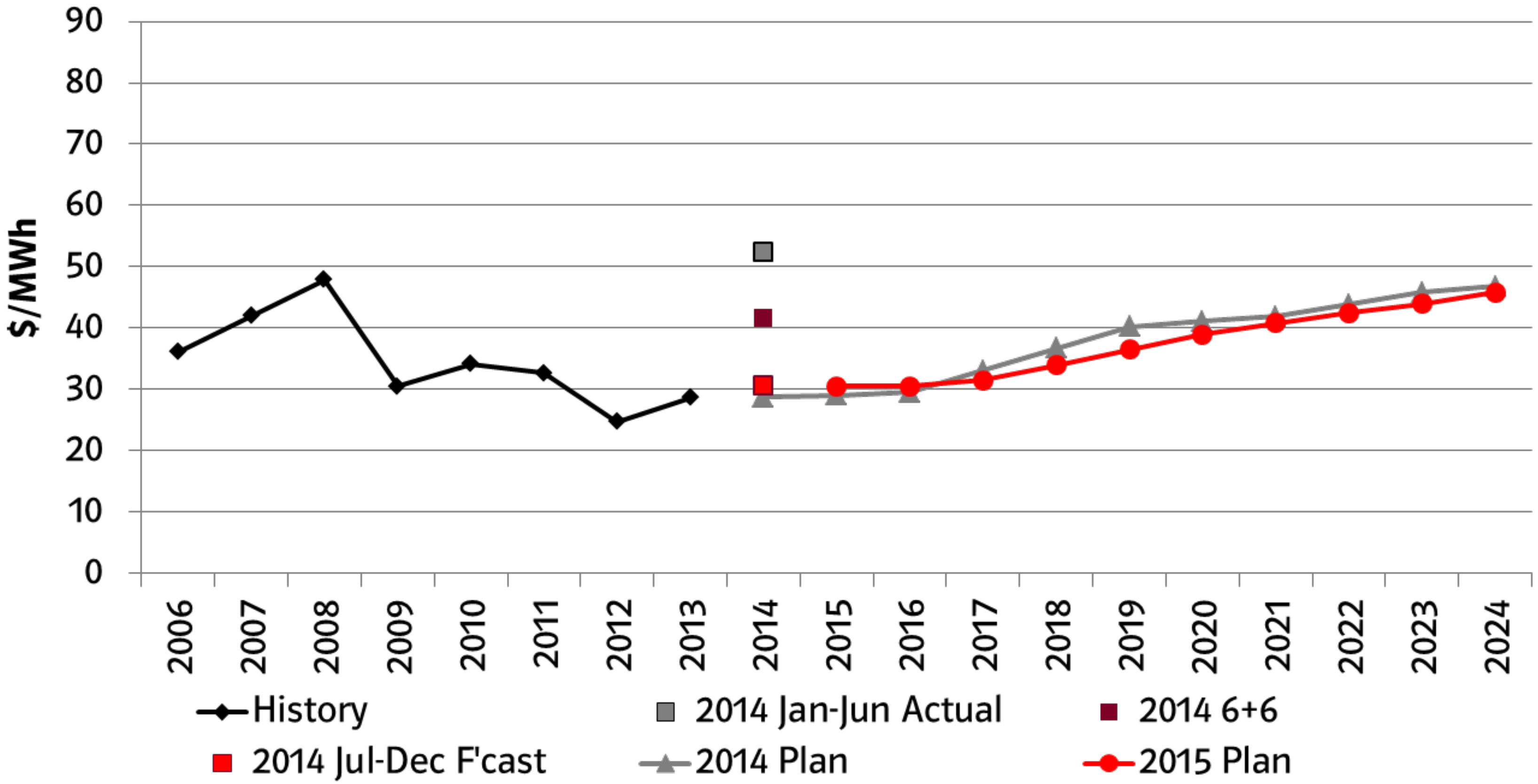
PPL companies

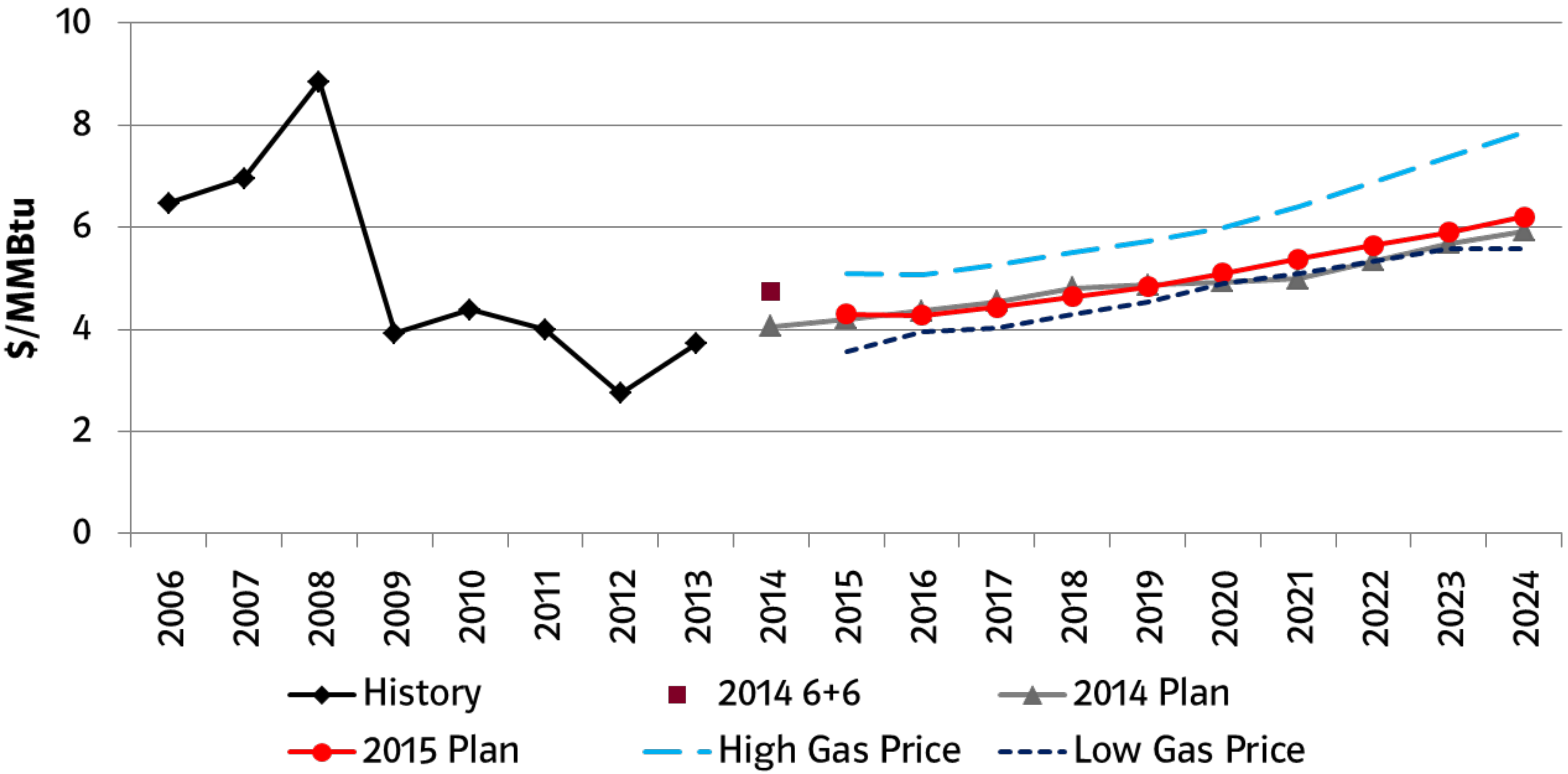


- *2015-2017 prices are ICE forward market prices as of June 23, 2014.*
- *2018-2019 prices are interpolated.*
- *Long-term prices from 2020 are modeled in AURORA.*



- *2015-2017 prices are ICE forward market prices as of June 23, 2014.*
- *2018-2019 prices are interpolated.*
- *Long-term prices from 2020 are modeled in AURORA.*

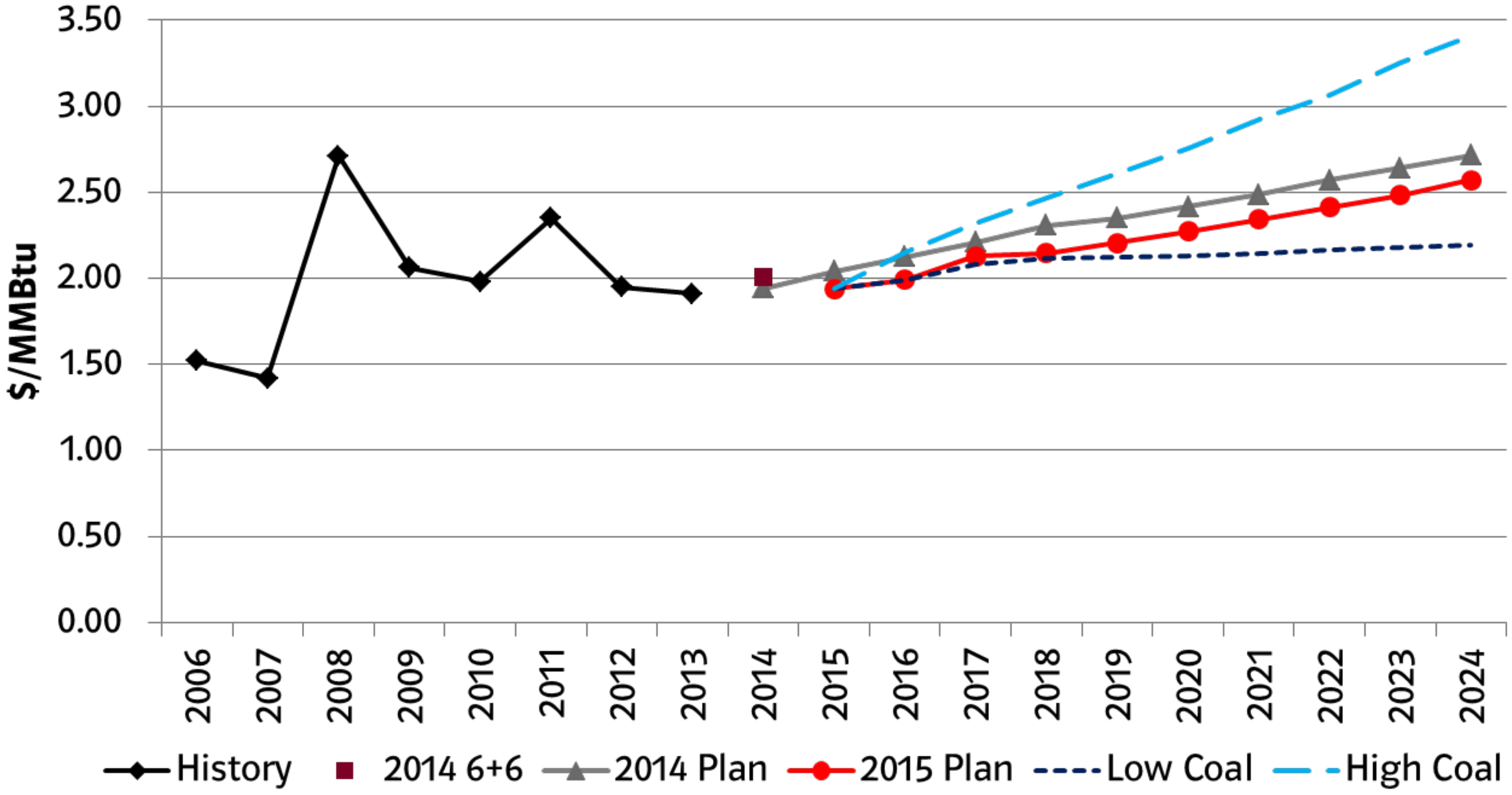
Henry Hub natural gas outlook slightly higher in near term



- *2015-2019 prices are NYMEX forward market prices as of June 23, 2014.*
- *2020-2021 prices are interpolated.*
- *Long-term prices from 2022 are EIA's Annual Energy Outlook Reference Case (May 2014).*
- *Does not include long-term CO_2-related impacts*

PPL companies

Illinois Basin high sulfur coal prices lower



- *Coal prices represent blend of bid information and Wood Mackenzie's Spring 2014 outlook through 2019. Thereafter, prices reflect EIA's (May 2014) forecasted growth rates.*

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Highest market electric price variances occur in January and February

Market Price Comparison

Market Price	2015 Plan			2014 Plan			2015 Plan - 2014 Plan		
$/MWh	Peak	Off-Peak	Weekend	Peak	Off-Peak	Weekend	Peak	Off-Peak	Weekend
Jan-15	64.93	44.22	49.08	41.90	31.87	34.64	23.04	12.35	14.44
Feb-15	58.77	40.50	43.35	41.90	32.17	34.52	16.88	8.33	8.82
Mar-15	47.94	32.59	38.18	39.18	28.37	32.43	8.76	4.22	5.75
Apr-15	38.83	27.84	34.17	39.24	27.85	33.79	-0.41	-0.01	0.38
May-15	40.15	22.26	32.38	40.23	22.65	32.63	-0.08	-0.39	-0.25
Jun-15	43.54	20.99	36.45	44.33	21.49	38.85	-0.79	-0.51	-2.40
Jul-15	59.32	23.94	40.55	52.14	24.42	41.89	7.18	-0.48	-1.33
Aug-15	52.69	24.43	35.25	52.14	25.10	38.49	0.55	-0.67	-3.24
Sep-15	36.40	21.50	30.11	39.78	23.98	34.22	-3.38	-2.49	-4.10
Oct-15	34.25	24.12	29.09	38.03	26.51	31.16	-3.77	-2.39	-2.07
Nov-15	34.92	26.49	28.69	37.98	28.23	30.56	-3.06	-1.74	-1.87
Dec-15	41.62	27.59	32.87	39.60	27.99	33.57	2.02	-0.40	-0.70
Jan-16	58.73	41.93	46.23	43.16	32.05	34.64	15.57	9.89	11.59
Feb-16	58.73	42.69	45.79	43.16	32.30	34.74	15.57	10.39	11.05
Mar-16	44.01	30.81	35.99	40.25	28.90	33.21	3.76	1.91	2.78
Apr-16	37.55	29.95	36.27	40.38	28.14	33.67	-2.84	1.80	2.59
May-16	38.78	22.92	33.95	41.08	23.50	34.49	-2.30	-0.57	-0.53
Jun-16	43.08	21.84	37.93	44.55	21.74	39.30	-1.47	0.10	-1.37
Jul-16	54.36	23.02	36.03	54.16	24.35	38.53	0.19	-1.33	-2.50
Aug-16	54.36	24.24	36.68	54.16	25.02	40.48	0.19	-0.78	-3.80
Sep-16	34.77	22.92	32.11	41.39	25.00	35.67	-6.61	-2.08	-3.56
Oct-16	33.84	24.86	29.65	38.30	28.27	32.88	-4.45	-3.41	-3.22
Nov-16	34.93	25.70	28.27	38.39	28.96	31.81	-3.46	-3.27	-3.54
Dec-16	39.01	26.71	31.45	38.30	28.03	33.23	0.71	-1.33	-1.78

PPL companies

2015 Fuel Cost Comparison – Annual Averages

Fuel Expense (¢/mmBTU)					**Delta**	
		2014 Forecast (6+6)	**2015 Plan 2015**	**2014 Plan 2015**	**2015 Plan 2015 - 2014 Plan 2015**	**% Change**
COAL	*BR*	*320*	*313*	*309*	*4*	*1%*
	GH	*226*	*231*	*243*	*(11)*	*-5%*
	GR	*232*	*234*	*NA*	*N/A*	*N/A*
	CR	*237*	*260*	*259*	*2*	*1%*
	MC	*238*	*241*	*241*	*0*	*0%*
	TC	*241*	*243*	*233*	*10*	*4%*
	TC PRB	*222*	*236*	*252*	*(16)*	*-7%*
GAS	*Gas BR*	*494*	*473*	*467*	*6*	*1%*
	Gas TC and CR7	*481*	*446*	*440*	*6*	*1%*
	Gas PR	*500*	*451*	*425*	*26*	*6%*
	Gas Haef	*781*	*693*	*687*	*6*	*1%*
OIL	*Oil*	*2245*	*2181*	*1794*	*387*	*22%*

2016 Fuel Cost Comparison – Annual Averages

Fuel Expense (¢/mmBTU)				**Delta**	
		2015 Plan 2016	**2014 Plan 2016**	**2015 Plan 2016 - 2014 Plan 2016**	**% Change**
COAL	*BR*	*312*	*315*	*(3)*	*-1%*
	GH	*237*	*250*	*(13)*	*-5%*
	GR	*N/A*	*N/A*	*N/A*	*N/A*
	CR	*N/A*	*N/A*	*N/A*	*N/A*
	MC	*234*	*244*	*(10)*	*-4%*
	TC	*231*	*242*	*(11)*	*-5%*
	TC PRB	*276*	*255*	*21*	*8%*
GAS	*Gas BR*	*472*	*483*	*(10)*	*-2%*
	Gas TC and CR7	*445*	*456*	*(11)*	*-2%*
	Gas PR	*450*	*440*	*10*	*2%*
	Gas Haef	*692*	*703*	*(10)*	*-1%*
OIL	*Oil*	*2,054*	*1,829*	*225*	*12%*

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PPL companies

2017 Fuel Cost Comparison – Annual Averages

Fuel Expense (¢/mmBTU)				Delta	
		2015 Plan 2017	2014 Plan 2017	2015 Plan 2017 - 2014 Plan 2017	% Change
COAL	*BR*	*325*	*329*	*(3)*	*-1%*
	GH	*252*	*260*	*(9)*	*-3%*
	GR	*N/A*	*N/A*	*N/A*	*N/A*
	CR	*N/A*	*N/A*	*N/A*	*N/A*
	MC	*250*	*257*	*(7)*	*-3%*
	TC	*240*	*250*	*(10)*	*-4%*
	TC PRB	*286*	*259*	*27*	*10%*
GAS	*Gas BR*	*488*	*502*	*(14)*	*-3%*
	Gas TC and CR7	*462*	*476*	*(14)*	*-3%*
	Gas PR	*467*	*460*	*7*	*2%*
	Gas Haef	*708*	*722*	*(14)*	*-2%*
OIL	*Oil*	*2,002*	*1,917*	*84*	*4%*

Peak Load and Energy Comparison

Peak Delta (2015 Plan - 2014 Plan)

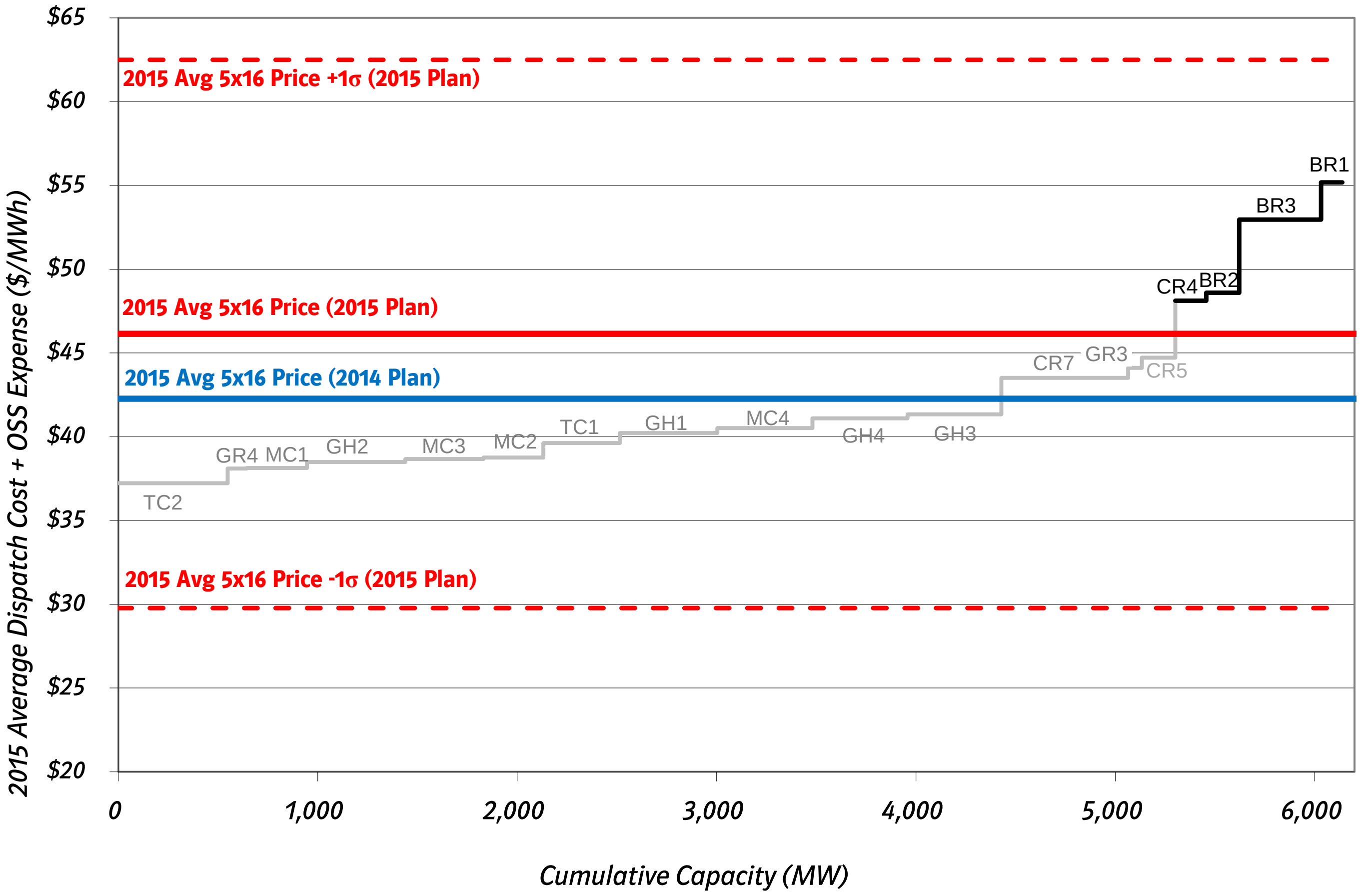
MW	2015	2016	2017	2018	2019
Jan	(19)	(22)	(23)	(16)	(206)
Feb	45	109	45	51	(130)
Mar	(61)	(65)	(62)	(60)	(206)
Apr	(76)	(74)	(74)	(70)	(198)
May	101	101	106	111	(31)
Jun	6	9	19	28	(155)
Jul	(237)	(196)	(212)	(205)	(386)
Aug	(63)	(62)	(66)	(78)	(360)
Sep	(178)	(181)	(177)	(175)	(334)
Oct	(96)	(97)	(93)	(88)	(216)
Nov	(97)	(99)	(96)	(91)	(230)
Dec	(18)	(17)	(14)	(11)	(189)
Peak	**(86)**	**(89)**	**(84)**	**(78)**	**(360)**

Energy Delta (2015 Plan - 2014 Plan)

GWh	2015	2016	2017	2018	2019
Jan	9	8	10	13	(84)
Feb	22	18	23	26	(61)
Mar	(27)	(29)	(27)	(25)	(108)
Apr	(36)	(36)	(35)	(33)	(106)
May	37	37	39	42	(36)
Jun	(23)	(24)	(21)	(18)	(105)
Jul	(146)	(147)	(145)	(143)	(237)
Aug	(97)	(99)	(96)	(93)	(189)
Sep	(89)	(89)	(88)	(86)	(166)
Oct	(59)	(59)	(58)	(56)	(132)
Nov	(53)	(54)	(53)	(50)	(129)
Dec	(15)	(15)	(13)	(11)	(106)
Total	**(476)**	**(489)**	**(464)**	**(435)**	**(1,457)**

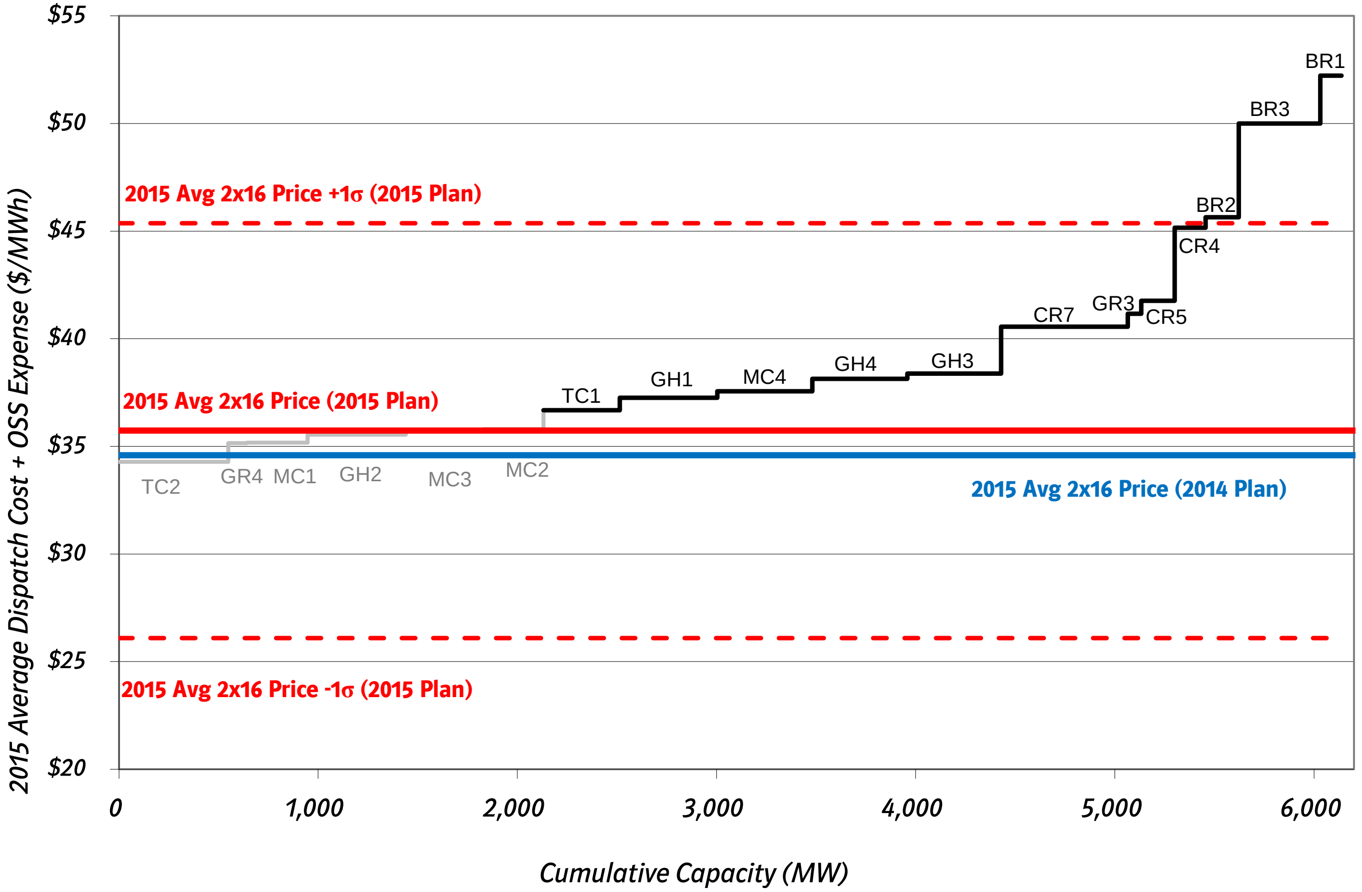
PPL companies

2015 5x16 Average Dispatch Cost (OSS)

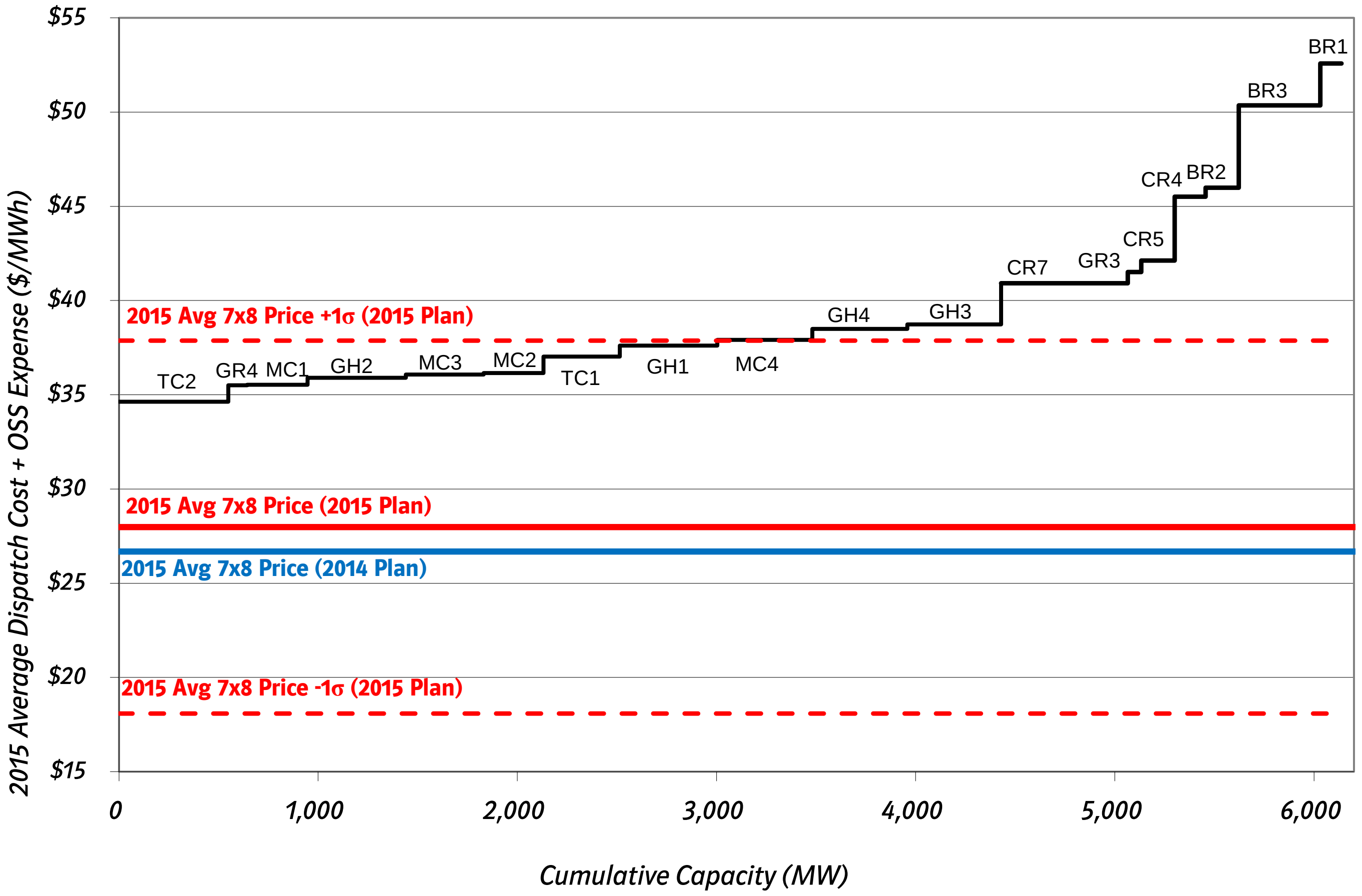


PPL companies

2015 2x16 Average Dispatch Cost (OSS)



2015 7x8 Average Dispatch Cost (OSS)



PPL companies

2015 Maintenance Schedule Changes

2015
Weekly Maintenance Detail

	GH1	GH2	GH3	GH4	BR1	BR2	BR3	GR3	GR4	CR4	CR5	CR6	MC1	MC2	MC3	MC4	TC1	TC2	CR7
1/5																			
1/12																			
1/19																			
1/26																			
2/2																			
2/9																			
2/16																			
2/23																			
3/2	⬛				⬛											🟨			
3/9	⬛				⬛									🟨					
3/16	⬛				⬛								🟥	🟨					
3/23	⬛				⬛								⬛	🟨				🟧	
3/30	⬛				⬛								⬛	⬛				⬛	
4/6	⬛				⬛								⬛	⬛				⬛	
4/13	⬛	🟨			⬛				🟨				⬛	⬛				🟥	
4/20	⬛	🟨			⬛				🟨				⬛	⬛					
4/27	🟨	🟥											🟨	🟥			⬛		
5/4		🟥											🟨	🟥					
5/11																			
5/18																			
5/25																			
Summer Season																			
9/7																			
9/14																			
9/21																			
9/28			🟥																
10/5		🟨	🟧				⬛										🟥		🟨
10/12		🟨	🟧				⬛										⬛		🟨
10/19		🟨	⬛			⬛	⬛	🟨									⬛		
10/26		🟨	⬛				⬛								⬛		⬛		
11/2		⬛	🟨				⬛								⬛		🟨		
11/9		⬛	🟨				⬛									⬛		🟥	
11/16		⬛					⬛											🟨	
11/23		⬛																	
11/30		🟨																	
12/7																			
12/14																			
12/21																			
12/28																			

🟥 Removed from 2014 Plan

🟨 Added to 2015 Plan

⬛ Unchanged

PPL companies

2016 Maintenance Schedule Changes

2016
Weekly Maintenance Detail

	GH1	GH2	GH3	GH4	BR1	BR2	BR3	GR3	GR4	MC1	MC2	MC3	MC4	TC1	TC2	CR7
1/4																
1/11																
1/18																
1/25																
2/1																
2/8																
2/15																
2/22																
2/29	🟨	🟥														
3/7	🟨	🟥														
3/14	🟨	🟥									⬛			⬛		
3/21		🟥							🟨	⬛	⬛					
3/28	🟧			🟨							⬛				⬛	
4/4	🟧			🟨	⬛	🟨	🟨				⬛				⬛	
4/11	🟧			🟨	⬛	🟨	⬛								⬛	
4/18	🟧			🟨	⬛	🟨	⬛					⬛			⬛	
4/25				🟧			🟧					⬛				
5/2				🟧								⬛				
5/9				🟧								⬛				
5/16												⬛				
5/23												⬛				
Summer Season																
9/5																
9/12																
9/19																
9/26			🟨													
10/3			🟨										⬛			
10/10			⬛										⬛			🟨
10/17			⬛			🟧							⬛			🟨
10/24		🟨				🟧							⬛			
10/31		🟨				🟧									⬛	
11/7		🟨										⬛				
11/14		🟨												⬛		
11/21																
11/28																
12/5																
12/12																
12/19																
12/26																

🟥 Removed from 2015 Plan
🟨 Added to 2016 Plan
⬛ Unchanged

PPL companies

2017 Maintenance Schedule Changes

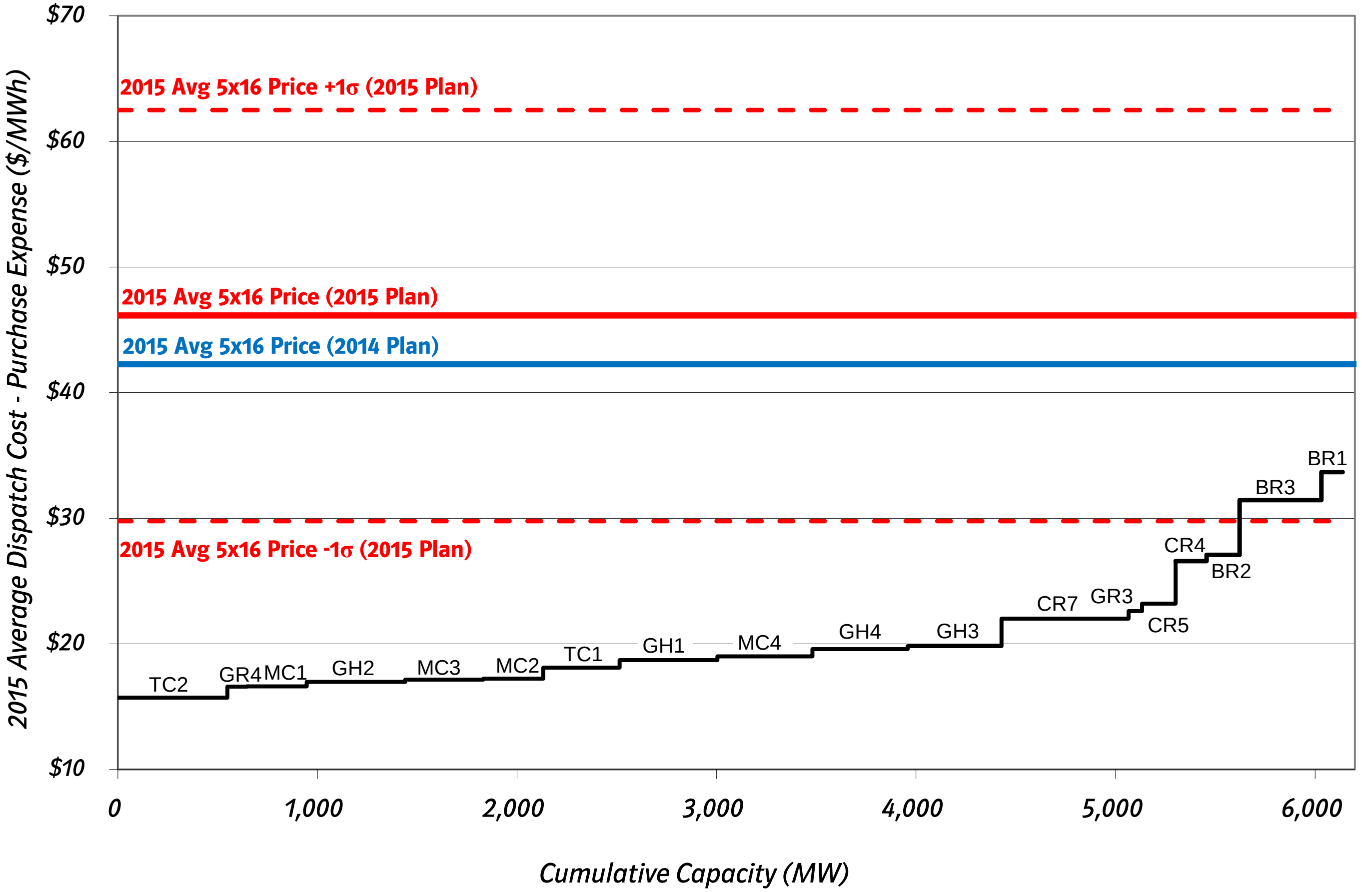
2017
Weekly Maintenance Detail

	GH1	GH2	GH3	GH4	BR1	BR2	BR3	MC1	MC2	MC3	MC4	TC1	TC2	CR7
1/2														
1/9														
1/16														
1/23														
1/30														
2/6														
2/13														
2/20														
2/27	⬛													
3/6	⬛					⬛								
3/13	🟨				⬛	⬛			⬛					
3/20		🟥	🟥			⬛							⬛	
3/27		🟥	🟥			⬛							⬛	
4/3		🟥	🟥			⬛							🟥	
4/10						⬛	⬛	⬛					🟥	
4/17				⬛		⬛		⬛						
4/24				⬛		⬛		⬛				⬛		
5/1				⬛				⬛						
5/8														
5/15														
5/22														
Summer Season														
9/4														
9/11														
9/18														
9/25												⬛		
10/2										⬛		⬛		
10/9		🟨	🟨							⬛		⬛		
10/16		🟨	🟨							⬛		⬛		🟥
10/23		🟨	🟨							⬛		⬛		🟥
10/30												⬛	⬛	
11/6											⬛	⬛		🟨
11/13												⬛		🟨
11/20														
11/27														
12/4														
12/11														
12/18														
12/25														

🟥 Removed from 2016 Plan　🟨 Added to 2017 Plan　⬛ Unchanged

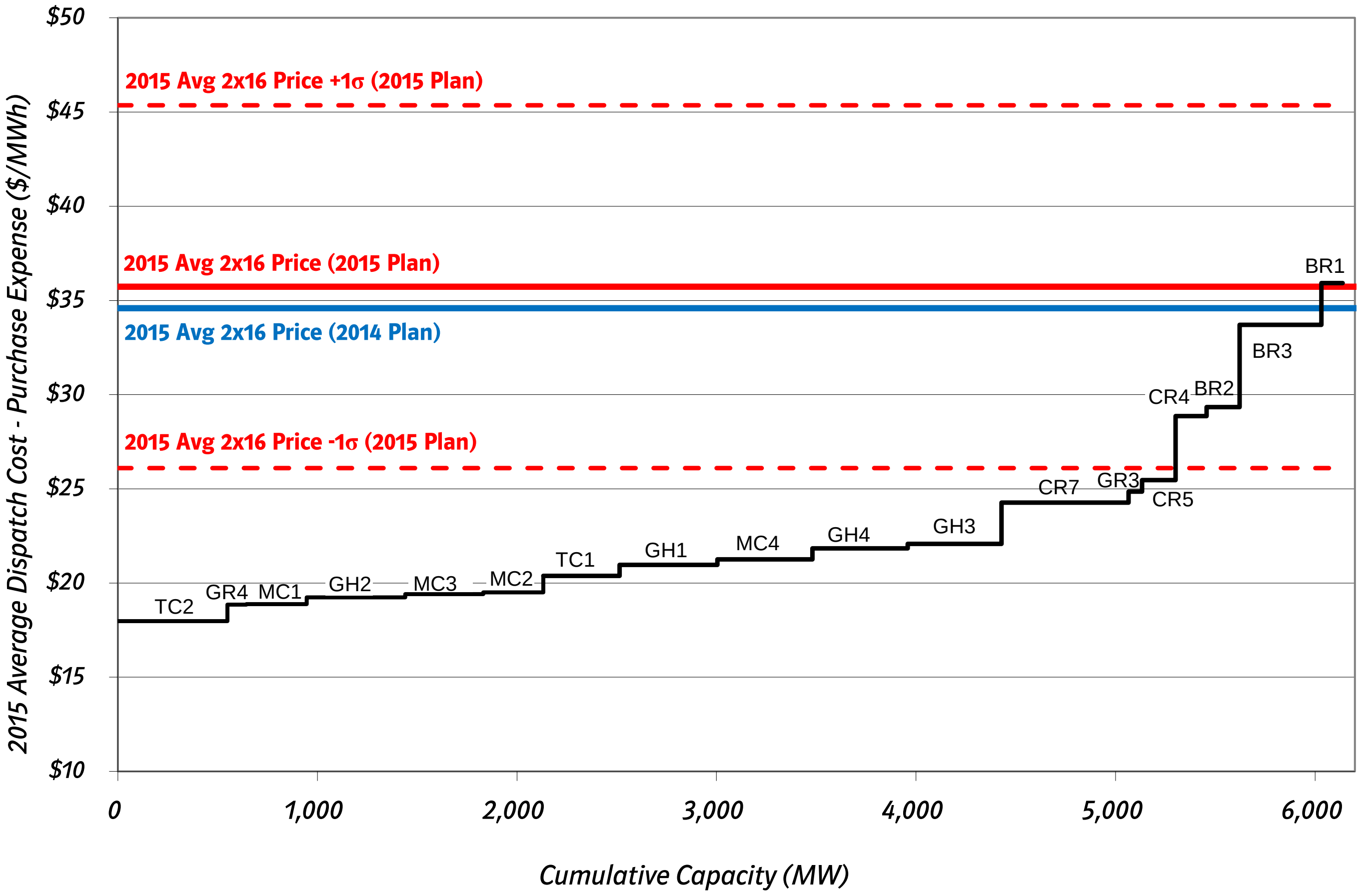
PPL companies

2015 5x16 Average Dispatch Cost (Purch)



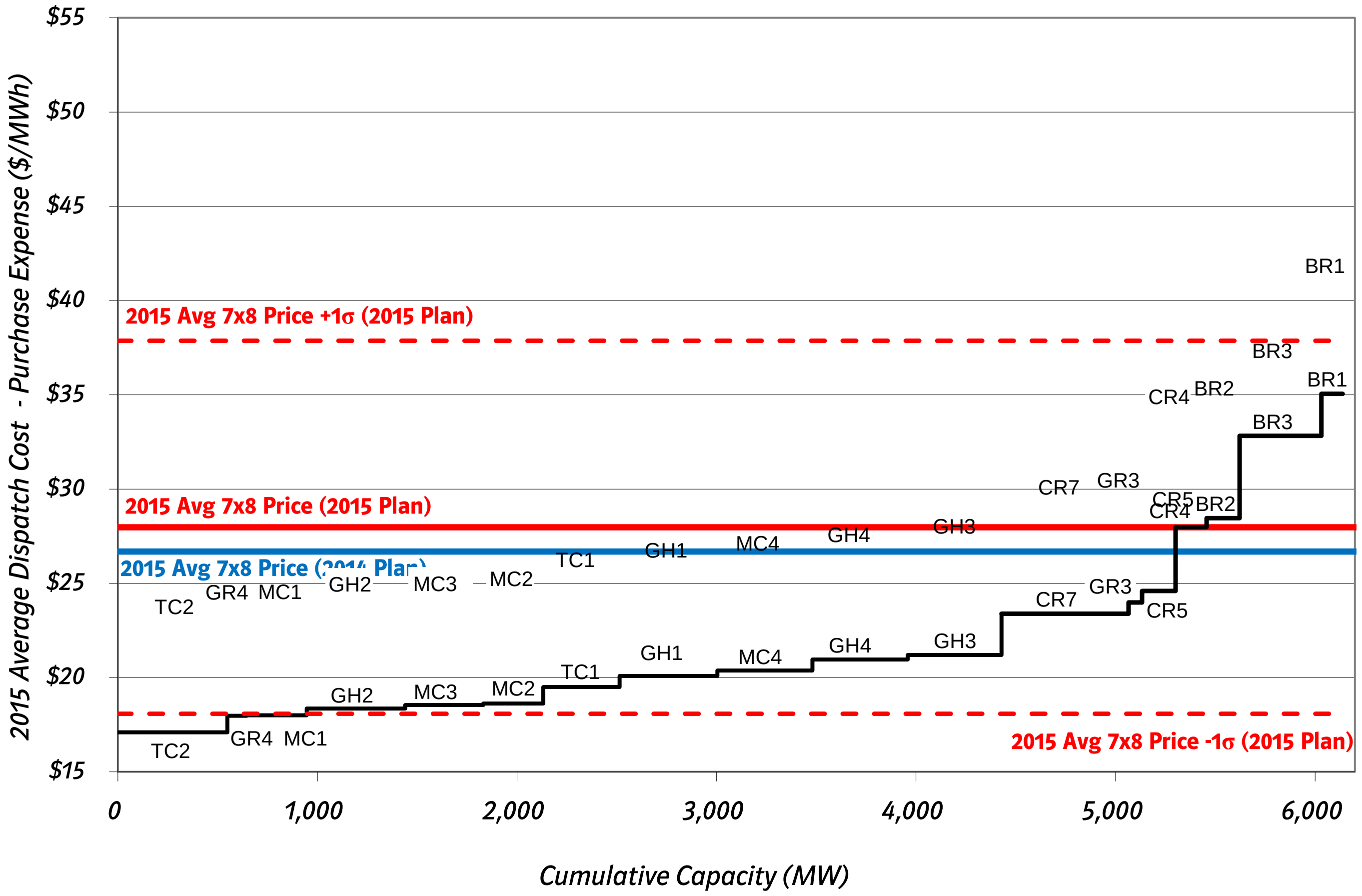
PPL companies

2015 2x16 Average Dispatch Cost (Purch)



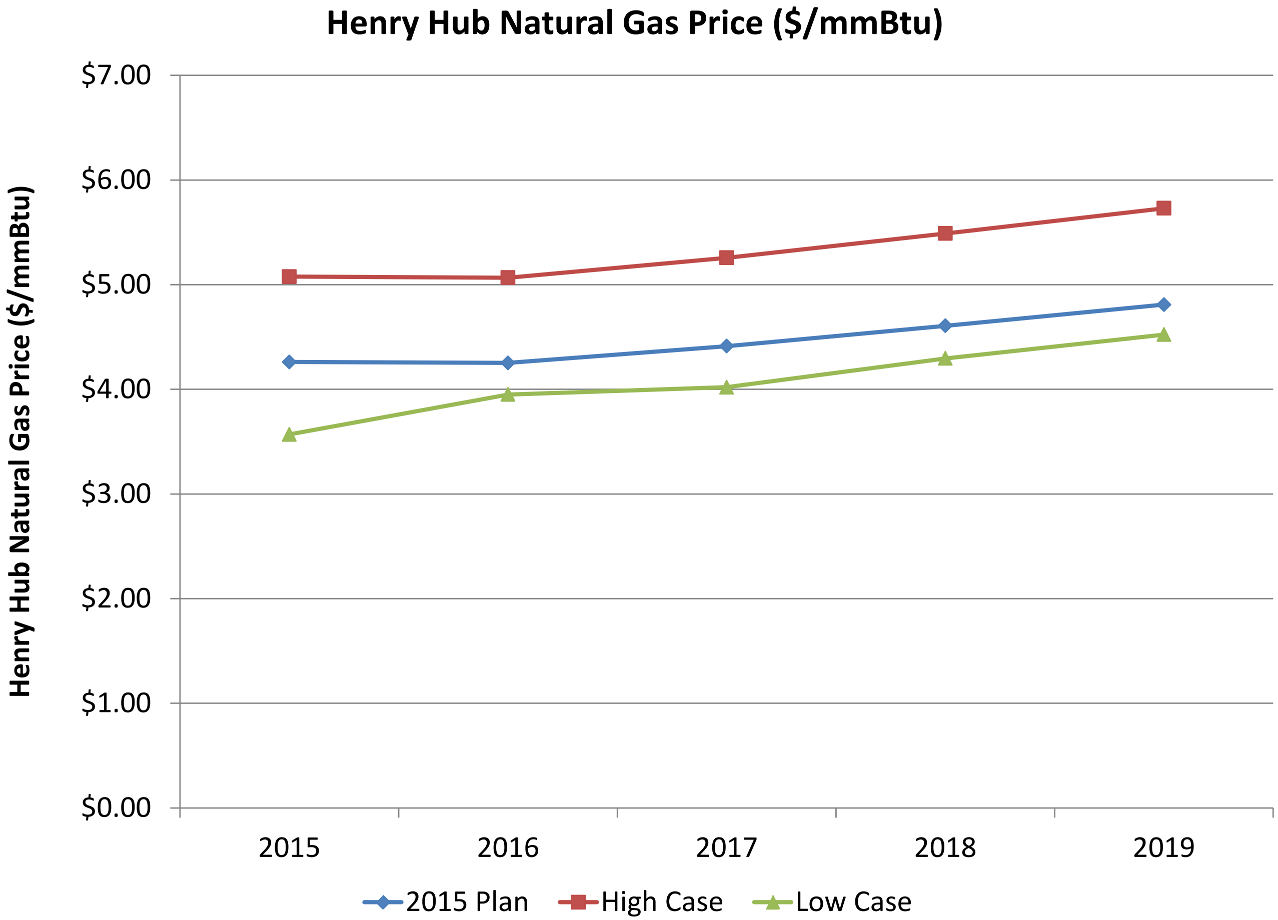
PPL companies

2015 7x8 Average Dispatch Cost (Purch)



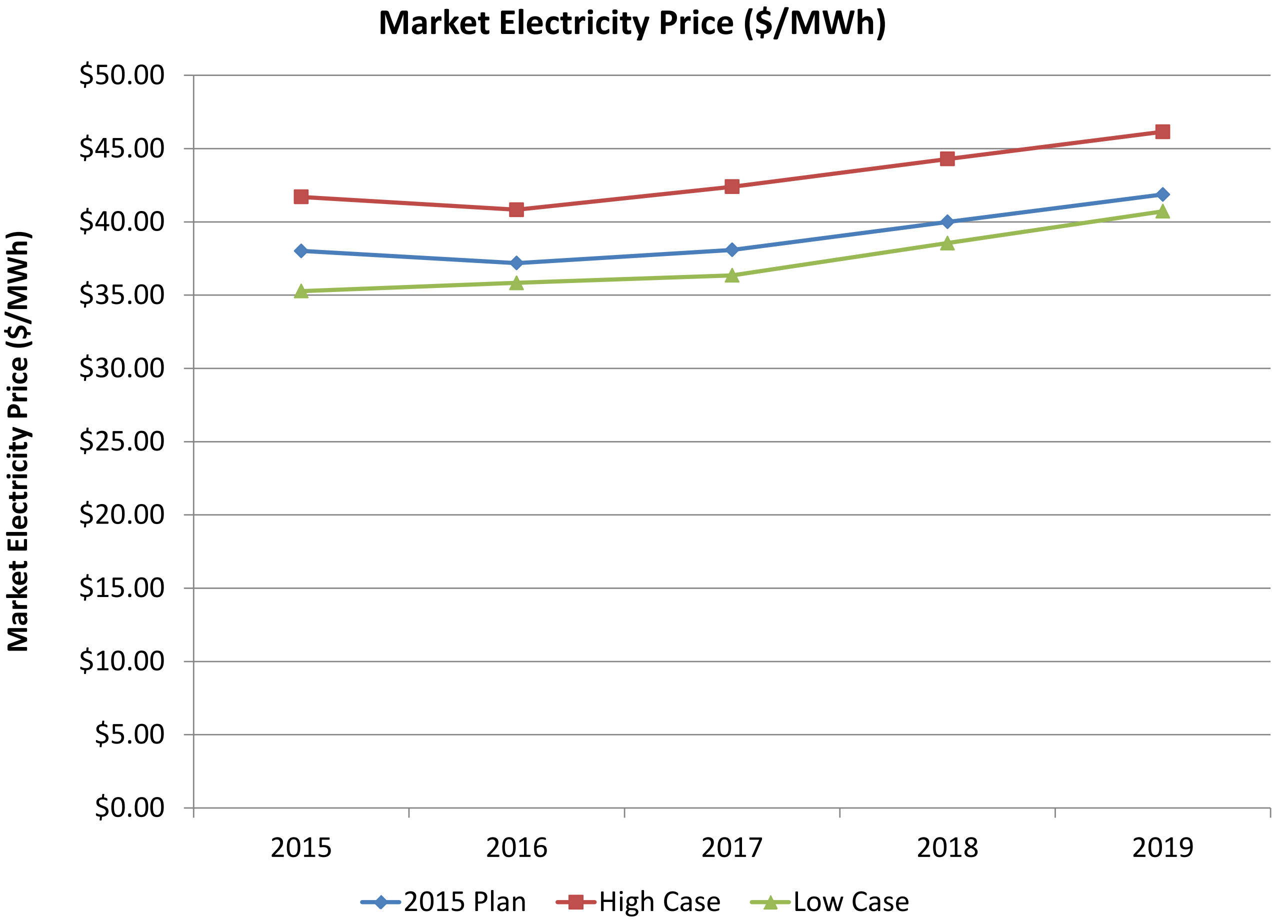
PPL companies

Natural Gas Price Scenarios



High and low gas price scenarios are from EIA.

Electricity Price Scenarios



High and low electricity price scenarios were developed in AURORA.

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Unit availability uncertainty

2015 EFORs Sensitivities

Percentile	**BR Sta**	**CR Sta**	**GR Sta**	**TC2**	**GH/MC/TC1**
10%	2.8%	5.1%	5.1%	6.0%	4.0%
Avg.	5.6%	8.1%	8.1%	6.0%	5.6%
90%	8.0%	12.0%	12.0%	12.0%	6.2%

2016 EFORs Sensitivities

Percentile	**BR Sta**	**CR Sta**	**GR Sta**	**TC2**	**GH/MC/TC1**
10%	2.8%	N/A	5.4%	6.0%	4.0%
Avg.	5.6%	N/A	8.4%	6.0%	5.6%
90%	8.0%	N/A	12.3%	12.0%	6.2%

2017 EFORs Sensitivities

Percentile	**BR Sta**	**CR Sta**	**GR Sta**	**TC2**	**GH/MC/TC1**
10%	2.8%	N/A	N/A	6.0%	4.0%
Avg.	5.6%	N/A	N/A	6.0%	5.6%
90%	8.0%	N/A	N/A	12.0%	6.2%

Note: EFORs for GH, MC and TC1 are modeled as a group and therefore have less variability.

PPL companies

Production costs and OSS contribution are impacted by uncertainty in weather/load, electricity/gas prices, and unit availability

Native Load Production Cost ($/MWh)	2015	2016	2017	2018	2019
5th Percentile	*27.82*	*28.40*	*29.70*	*30.96*	*32.01*
2015 Plan	*29.39*	*29.60*	*31.12*	*32.38*	*33.35*
95th Percentile	*30.97*	*31.24*	*32.82*	*34.28*	*35.27*

OSS Contribution ($M)	2015	2016	2017	2018	2019
5th Percentile	*1.7*	*2.2*	*1.8*	*1.4*	*1.4*
2015 Plan	*3.0*	*3.1*	*2.1*	*1.6*	*1.9*
95th Percentile	*4.5*	*4.0*	*3.6*	*2.7*	*2.7*

Fuel burn is impacted by uncertainty in weather/load, electricity/gas prices, and unit availability

Gas Burn (GBtu)	**2015**	**2016**	**2017**	**2018**	**2019**
5th Percentile	*27,371*	*27,283*	*27,865*	*30,632*	*28,203*
2015 Plan	*36,290*	*40,897*	*41,924*	*44,562*	*41,344*
95th Percentile	*48,200*	*48,890*	*50,399*	*51,570*	*48,321*

Coal Burn (GBtu)	**2015**	**2016**	**2017**	**2018**	**2019**
5th Percentile	*294,495*	*296,165*	*293,483*	*296,468*	*294,244*
2015 Plan	*317,726*	*312,740*	*311,367*	*311,225*	*308,593*
95th Percentile	*333,665*	*334,514*	*335,156*	*334,011*	*330,005*

- *5th and 95th percentile values are based on the results of 1,200+ simulations. Range of outcomes reflects the uncertainty in weather/load, market electricity/gas prices, and unit availability.*

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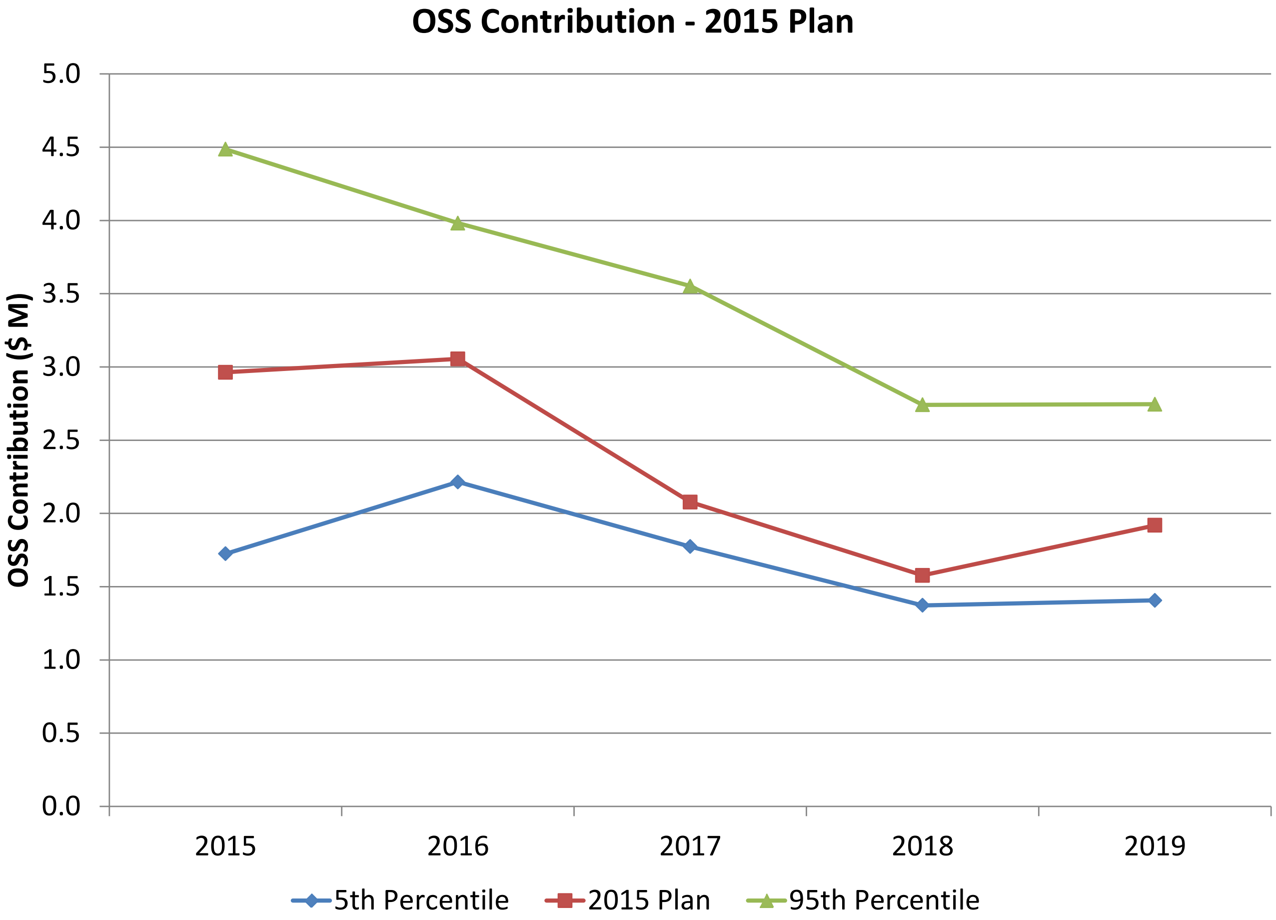
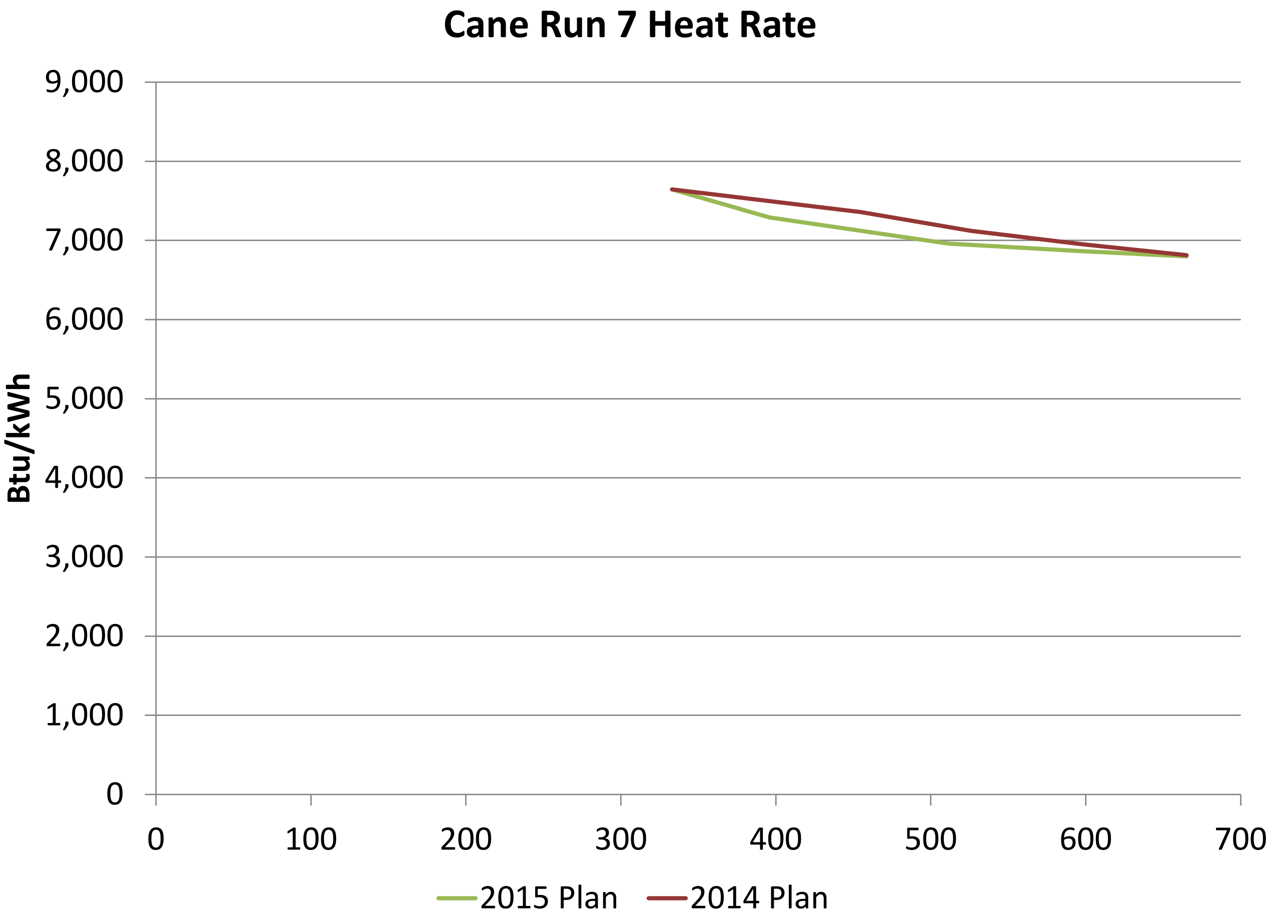
OSS contribution is impacted by uncertainty in weather, electricity/gas prices, and unit availability



PPL companies

In 2015 Plan, Cane Run 7 heat rate curve is slightly flatter



PPL companies

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LOB name here

2015 Business Plan

Month, Day, Year

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Plan Highlights

- Key Items

Major Assumptions

- State major assumptions

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Financial Review – Prior Plan to Target Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OPEX (O&M and BTL):					
Prior Plan Amount					
Adjustments/Transfers:					
xxx					
xxx					
xxx					
xxx					
Current Target					

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
GMEXP (OCOS):					
Prior Plan Amount					
Adjustments/Transfers:					
xxx					
xxx					
xxx					
xxx					
Current Target					

- *Use more than 1 page if needed*

Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M Expenses Only:							
Labor							
Non labor (category 1)							
Non labor (category 2)							
Non labor (category 3)							
Non labor (category 4)							
Non labor (category 5)							
Subtotal O&M Expense	-	-	-	-	-	-	-
Other Income/Expense* * (see OIE slide for detail)							
Total OPEX	-	-	-	-	-	-	-

PPL companies

Financial Performance - OPEX

2013-2019 Other Income/Expenses (incl. BTL)
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OIE/BTL Expenses Only:							
Labor							
Contributions							
Employee Recognition							
Meals and Meetings Exp.							
Other							
Non labor (category 5)							
Total OIE / BTL Expense	-	-	-	-	-	-	-

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PPL companies

2015-2019 O&M / Other Expense Reconciliation
($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Target					
Drivers:					
xxx					
xxx					
xxx					
xxx					
Current Plan					

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PPL companies

Financial Performance

2013-2019 Margin Expenses / Cost of Sales
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Margin Expenses							
Mechanism Recoverable:							
xxx							
xxx							
Total							
All other Cost of Sales:							
xxx							
xxx							
Total							
Total Margin/Cost of Sales	-	-	-	-	-	-	-

- *IF APPLICABLE*

PPL companies

2015-2019 Margin/Cost of Sales Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Mechanism recoverable					
Prior Plan / Target					
Drivers					
xxx					
xxx					
xxx					
xxx					
Current Plan					
Other					
Prior Plan / Target					
Drivers					
xxx					
xxx					
xxx					
xxx					
Current Plan					

- *IF APPLICABLE*

LG&E KU
PPL companies

2013-2019 Capital Breakdown (w COR) – Accrual Basis ($000)

Project	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Environmental							
XXX							
XXX							
New Generation Capacity							
XXX							
XXX							
Generation							
XXX							
XXX							
Distribution and Metering							
XXX							
XXX							
Transmission							
XXX							
XXX							
Other							
XXX							
XXX							
Total Capital and Cost of Removal							

PPL companies

2015-2019
Capital Reconciliation (w COR) –Accrual Basis
($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Prior Plan					
Changes:					
xxx					
xxx					
xxx					
xxx					
Current Plan					

PPL companies

Financial Performance

2013-2019 Headcount

Department	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**
From 2014 Business Plan							
Variance to 2014 Business Plan		0	0	0			

Year to Year Increases (Decreases)	2014	2015	2016	2017	2018	2019
1.) Maintenance /Operational						
2.) Compliance – NERC, FERC, CIP, etc.						
3.) EPA/Environmental						
4.) Administrative/Corporate						
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**
Contractor Offsets By Year: (New hire reducing contractor use)						

Operational Performance

Key Performance Indicators

	2013	2014	2015	2016	2017	2018	2019
KPI	Year End	Forecast	Budget	Plan	Plan	Plan	Plan

Plan Risks

- List plan risks

Appendix

2013-2019
Year over Year Walk Forward OPEX and Other Expense

2013 Actual
xxx
xxx
xxx
2014 FC
xxx
xxx
xxx
2015 Budget
xxx
xxx
xxx
2016 Plan
xxx
xxx
xxx
2017 Plan
xxx
xxx
xxx
2018 Plan
xxx
xxx
xxx
2019 Plan

2013-2019
Year over Year Walk Forward
GMEXP / Cost of Sales

2013 Actual
xxx
xxx
xxx
2014 FC
xxx
xxx
xxx
2015 Budget
xxx
xxx
xxx
2016 Plan
xxx
xxx
xxx
2017 Plan
xxx
xxx
xxx
2018 Plan
xxx
xxx
xxx
2019 Plan

2014-2019
Headcount progression

2014 Headcount (As of July 2014)
xxx
xxx
xxx
2014 Headcount FC - Year End
xxx
xxx
xxx
2015 Headcount Budget
xxx
xxx
xxx
2016 Headcount Plan
xxx
xxx
xxx
2017 Headcount Plan
xxx
xxx
xxx
2018 Headcount Plan
xxx
xxx
xxx
2019 Headcount Plan

Describe type of work not necessarily positions – should explain need for additional headcount year over year (CIP; customer Service; compliance; etc.)

Headcount & Employee Expense

2014-2019 Headcount

Business Unit Name	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Total Full Time & Part Time Headcount (without interns)	0	0	0	0	0	0

Employee Related Expenses	2014	2015	2016	2017	2018	2019
1.) Training & Development						
2.) Travel						
3.) Meals and Expenses						
4.) Employee Recognition						
5.) Employee Dues and Memberships						
TOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Average Employee Expense per number of employees	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**

Note: For the Employee related expense line items above, please use the following expenditure types:

1) 0778 Tuition Reimbursement, 0634 Education & Training
2) 0641 Travel
3) 0642 Meals – Partially Deductible, 0643 Meals – Fully Deductible
4) 0636 Employee Recognition
5) 0654 Employee Dues/Memberships

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2013-2019
Other Balance Sheet Costs
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Stores Expense							
Labor							
Non labor							
Total							
Local Engineering							
Labor							
Non labor							
Total							
Other Balance Sheet							
Labor							
Non labor							
Total							
Total Other Costs							

- THIS SLIDE USED FOR SUMMARY; only use costs that apply to your area – others can be deleted

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PPL companies

Corporate

2015 Business Plan

September 17, 2014

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PPL companies

Major Assumptions

- *Pension based on actuarial calculations and assumptions:*
  - *Increases from previous plan driven by change from BB mortality scale to RP-2014/MP-2014 mortality scale, change in the discount rate and the change in LGE bargaining plan multipliers ($13M impact included $3M increase to capital and $10M increase in O&M)*
  - *Increases above partially offset by demographic gains, change in asset returns and favorable impact of 2014 higher funding level*
- *Medical expense adjusted for headcount and 2014 actuals with increases of 6% annually for 2015-2019*
  - *Premium costs increase effectively managed to only 4% increase*
  - *Additional funding included for employee wellness and health programs to continue and expand the promotion of healthy lifestyle maintenance*
- *Property insurance increases driven by Capital investments and growth of assets in plan years; insurance expense growth is lower than previously budgeted*

Major Assumptions

- *Assumed amortization of regulatory assets will continue through plan periods based on KPSC orders*
- *Assumed a 2% annual increase on the minimum base rent and a 2.5% annual increase for operating expense (per contract) for the LGE Center Lease*
- *Allocation of indirect PPL expenses based on most current amounts provided that may be revised as further planning processes continue*
- *Incentive expenses currently based on most recent calculations provided this year*

Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M Expenses Only:							
Pension	36,762	15,093	37,473	31,584	27,784	26,417	23,172
Post Retirement	8,045	7,610	8,914	8,125	6,179	5,763	5,582
Medical/Dental	23,604	24,403	29,023	30,849	32,671	34,601	36,646
Payroll taxes	17,925	20,711	21,107	21,848	22,503	23,178	23,874
401k Drop In	10,057	11,003	11,759	12,202	12,738	13,307	13,912
Other Benefits	4,585	5,232	6,222	6,449	6,664	6,888	7,120
PPL Expense Allocation	13,507	13,729	15,123	15,361	15,646	16,106	16,369
Incentive Compensation	14,376	14,228	14,078	13,409	13,125	13,139	13,204
Insurance Expense	12,064	12,646	13,140	15,549	17,333	18,893	20,711
Amortization of Regulatory Assets	16,083	16,041	15,976	15,759	14,764	13,270	13,270
LGE Center and Other Facilities Ex	3,169	10,088	10,016	9,950	10,086	10,232	10,398
A&G Transfer Credit	(7,655)	(9,273)	(10,726)	(11,049)	(11,284)	(11,064)	(11,487)
IMEA/IMPA billings	(12,880)	(13,334)	(13,650)	(14,024)	(15,944)	(15,746)	(16,829)
Other	(1,224)	4,430	2,555	2,610	2,641	4,710	4,776
Subtotal O&M Expense	138,418	132,607	161,010	158,622	154,907	159,695	160,717
Other Income/Expense* * (see OIE slide for detail)	(1,996)	(3,111)	(2,581)	(2,998)	(1,857)	(1,749)	(1,751)
Total OPEX	136,423	129,496	158,429	155,624	153,049	157,946	158,966

PPL companies

Financial Performance - OPEX

2013-2019 Other Income/Expenses (incl. BTL)
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OIE/BTL Expenses Only:							
IMEA/IMPA Billings	(1,303)	(1,350)	(1,319)	(1,321)	(1,323)	(1,322)	(1,323)
Other Income	(1,905)	(2,765)	(2,256)	(2,681)	(1,547)	(1,450)	(1,461)
Other Expenses	1,213	1,004	994	1,003	1,013	1,023	1,033
Total OIE / BTL Expense	(1,996)	(3,111)	(2,581)	(2,998)	(1,857)	(1,749)	(1,751)

LG&E KU
PPL companies

2015-2019 O&M / Other Expense Reconciliation
($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Plan Expectation	159,565	160,953	166,509	171,546	175,786
Drivers:					
Pension	9,517	4,530	403	(280)	(3,526)
Post Retirement	717	884	691	450	269
Medical/Dental	(1,435)	(1,877)	(2,634)	(3,629)	(4,597)
Payroll taxes	(1,065)	(990)	(1,020)	(1,050)	(1,082)
Other Burden Expense	(1,458)	(1,500)	(1,498)	(1,495)	(1,489)
A&G Transfer Credit	(1,879)	(2,009)	(2,762)	(2,298)	(3,140)
IMEA/IMPA Billings	(267)	405	(1,271)	(1,214)	(1,936)
Insurance	(1,696)	(1,279)	(1,084)	(1,262)	(1,346)
Other	(3,570)	(3,492)	(4,284)	(2,821)	28
Current Plan	158,429	155,624	153,049	157,946	158,966
Variance	1,136	5,329	13,460	13,600	16,819

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PPL companies

PPL companies

Energy Supply and Analysis

2015 Business Plan

September 17, 2014

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Plan Highlights

Key Objectives

- Optimize the utilization of existing assets to provide reliable, low cost energy.
- Procure coal and gas necessary to cost-effectively operate generating plants.
- Provide high quality analysis to enhance decision-making.
- Implement processes required to meet reliability standards.
- Improve analysis capability and knowledge related to retail customer energy usage to support energy efficiency and resource planning efforts.

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PPL companies

Major Assumptions

- Analysis needed to support major company initiatives (KPSC filings) and strategic planning can be met by existing staff levels.
- Potential for Municipal rate case litigation and proposed CO_2 regulations will require significant support in 2015.
- Retirement risk in Fuels department is growing over the planning period so a new position is temporarily planned for that area in early-2015 to allow adequate time for training and development.
- Integrating CR7 into normal fleet dispatch will be accomplished with no major issues.

PPL companies

Financial Performance

2013-2019 OSS Margin
($000)

	2013	2014	7+5 2014	2014 BP	2015 Business Plan				
	Actual	Budget	Forecast	2015	2015	2016	2017	2018	2019
OSS Margin before Transmission Expense	5,846	2,988	11,459	1,972	3,975	4,234	3,040	2,395	2,910
Transmission Expense (Internal)	1,245	849	1,368	715	1,006	1,157	978	810	975
Total OSS Margin	4,601	2,139	10,091	1,257	2,969	3,077	2,062	1,585	1,935

Off-system Sales Volume-GWh

	2013 Actual	2014 Budget	7+5 2014 Forecast	2014 BP 2015	2015	2016	2017	2018	2019
On-peak	318	128	260	114	178	201	165	131	151
Off-peak	51	28	46	17	35	41	38	31	34
Weekend	132	115	82	67	97	110	91	79	104
Total	501	271	388	198	310	352	294	241	289

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PPL companies

Financial Review – Prior Plan to Current Expectation Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OPEX (O&M and BTL):					
Prior Plan Amount	9,594	9,790	10,140	10,336	10,627
Adjustments/Transfers:					
Software transferred to I.T.	(237)	(242)	(247)	(252)	(257)
BP Efficiency Savings	(457)	(424)	(540)	(496)	(542)
Current Expectation	8,900	9,124	9,353	9,588	9,828

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
GMEXP (OCOS):					
Prior Plan Amount	6,273	6,143	6,778	7,541	9,668
Adjustments/Transfers:					
2019 Expectation based on 2.5% inflation from '18					(1,938)
Current Expectation	6,273	6,146	6,778	7,542	7,730

PPL companies

Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M Expenses Only:							
Labor	7,598	7,538	7,778	7,858	7,984	8,316	8,506
Non labor Regulated Trading	168	212	220	225	229	234	239
Non labor Business Information	5	-	-	-	-	-	-
Non labor Director Energy PF&A	21	18	18	18	19	19	19
Non labor Generation Planning	252	203	18	18	18	19	19
Non labor Economic Analysis	128	96	94	95	97	99	101
Non labor Sales Analysis	88	105	50	50	51	53	54
Non labor VP Energy Supply	21	(25)	17	18	18	18	19
Non labor Allocated Support	1	2	-	-	-	-	-
Non labor Fuel Management	73	42	68	69	70	72	74
Non labor Fuels Admin	242	468	391	396	404	412	420
Non labor Fuels Risk Management	(5)	63	64	66	67	68	69
Non labor Other	56	-	-	-	-	-	-
Subtotal O&M Expense	8,648	8,722	8,718	8,813	8,957	9,310	9,520
Other Income/Expense* * (see OIE slide for detail)	49	138	38	39	40	41	41
Total OPEX	8,697	8,860	8,756	8,852	8,997	9,351	9,561

PPL companies

Financial Performance - OPEX

2013-2019 Other Income/Expenses (incl. BTL)
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OIE/BTL Expenses Only:							
Labor	-	-	-	-	-	-	-
Contributions	54	69	36	37	38	39	39
Employee Recognition	-	-	-	-	-	-	-
Meals and Meetings Exp.	4	69	2	2	2	2	2
Other (relocation & lobbying)	(9)	-	-	-	-	-	-
Total OIE / BTL Expense	49	138	38	39	40	41	41

2015-2019 O&M / Other Expense Reconciliation
($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Expectation	8,900	9,124	9,353	9,588	9,828
Drivers:					
Additional non-labor reductions	(144)	(272)	(356)	(237)	(267)
Current Plan	8,756	8,852	8,997	9,351	9,561

PPL companies

Financial Performance

2013-2019 Margin Expenses / Cost of Sales
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Margin Expenses							
Mechanism Recoverable:							
	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-
All other Cost of Sales:							
Industrial Coal Sales	688	831	832	832	832	849	866
EKPC NITS	902	2,137	3,116	2,833	2,897	2,955	3,014
EKPC 25 Intermittent	n/a	475	497	537	580	592	604
OSS RTO	1,008	1,549	807	917	731	554	647
OSS Intercompany XM	1,245	964	1,006	1,157	978	810	975
OSS 3rd Party XM	12	8	-	-	-	-	-
NL RTO	67	177	219	236	284	309	311
NL Intercompany XM	549	1,367	620	516	593	696	764
NL 3rd Party XM	1,473	614	242	199	230	252	264
Total	5,944	8,122	7,340	7,228	7,125	7,017	7,445
Total Margin/Cost of Sales	5,944	8,122	7,340	7,228	7,125	7,017	7,445

PPL companies

2015-2019 Margin/Cost of Sales Reconciliation
($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
<u>Mechanism recoverable</u>					
Prior Plan / Expectation	-	-	-	-	-
Drivers					
Current Plan	-	-	-	-	-
<u>Other</u>					
Expectation	6,273	6,146	6,778	7,542	7,730
Drivers:					
EKPC	1,122	787	842	860	876
RTO - OSS	456	626	329	(232)	(817)
Interco Transmission - OSS	292	398	121	(730)	(1,929)
RTO - NL	(186)	(136)	(124)	26	(65)
Interco Transmission - NL	(490)	(477)	(696)	(409)	(229)
3rd Party Transmission - NL	(127)	(116)	(125)	(23)	(42)
Industrial Coal Sales	-	-	-	(17)	(17)
Expectation calc vs. 2014 BP	-	-	-	-	1,938
Current Plan	7,340	7,228	7,125	7,017	7,445

PPL companies

2013-2019 Capital Breakdown (w COR) – Accrual Basis ($000)

Project	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Other							
CTS	*358*	*208*	-	-	-	-	-
Power Base Software	*40*	-	-	-	-	-	-
Other Analysis Tools	*13*	*20*	*257*	*257*	*257*	*257*	*257*
Total Capital and Cost of Removal	*411*	*228*	*257*	*257*	*257*	*257*	*257*

PPL companies

2015-2019
Capital Reconciliation (w COR) –Accrual Basis
($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Prior Plan	256	256	256	256	256
Changes:					
Burdens	1	1	1	1	1
Current Plan	257	257	257	257	257

Financial Performance

2013-2019 Headcount

Department	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Power Supply	22	23	23	23	23	23	23
Director Energy Supply FP &A	2	2	2	2	2	2	2
Economic Analysis	6	6	6	6	6	6	6
Sales Analysis	5	6	6	6	6	6	6
Generation Planning	7	8	8	7	7	7	7
VP Energy Supply	2	2	2	2	2	2	2
Fuels	17	17	17	17	17	17	17
TOTAL	**61**	**64**	**64**	**63**	**63**	**63**	**63**
From 2014 Business Plan		64	64	64			
Variance to 2014 Business Plan		0	0	-1			

Year to Year Increases (Decreases)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
1.) Maintenance /Operational						
2.) Compliance – NERC, FERC, CIP, etc.						
3.) EPA/Environmental						
4.) Administrative/Corporate	3	0	-1	0	0	0
TOTAL	**3**	**0**	**-1**	**0**	**0**	**0**
Contractor Offsets By Year: (New hire reducing contractor use)	0	0	0	0	0	0

PPL companies

Plan Risks

- OSS margin impacts of native load variation due to weather, unit availability, and transmission system capacity
- Approval of Green River extension to April 16, 2016
- Trimble County 2 performance post burner replacement
- Cane Run 7 testing, commissioning date, and performance
- Coal unit performance in 2015 post installation of environmental retrofits

[redacted]

- Summer 2016 availability of Mill Creek 3 following baghouse/FGD installation
- Transition of system to fewer, larger units
- Workforce transition due to retirements

PPL companies

Appendix

PPL companies

2013-2019
Year over Year Walk Forward
OPEX and Other Expense
($000's)

2013 Actual	**8,697**
Change in labor	(59)
Higher estimated non-labor spending	222
2014 FC	**8,860**
Transfer software to I.T.	(237)
Change in labor excluding early hires and retirements	217
Non-labor reductions	(154)
Fuels early hire in January for July retirement in 2015	70
2015 Budget	**8,756**
Change in labor excluding early hires and retirements	221
Early hire in 2015 for 1/2 year not in 2016	(70)
Generation Planning retirement in mid-2016	(70)
Other	15
2016 Plan	**8,852**
Change in labor excluding early hires and retirements	196
Half year effect in 2017 of Gen Planning retirement in mid-2016	(70)
Other	19
2017 Plan	**8,997**
Change in labor excluding early hires and retirements	256
Fuels early hire in January for July retirement in 2018	78
Other	20
2018 Plan	**9,351**
Change in labor excluding early hires and retirements	267
Early hire in 2017 for 1/2 year not in 2019	(78)
Other	21
2019 Plan	**9,561**

LG&E KU
PPL companies

2013-2019
Year over Year Walk Forward
GMEXP / Cost of Sales
($000's)

2013 Actual	**5,944**
EKPC	1,235
OSS RTO/Interco XM	673
NL RTO/Interco & 3rd P XM	141
Industrial Coal Sales	130
2014 FC	**8,123**
EKPC	1,477
OSS RTO/Interco XM	(1,093)
NL RTO/Interco & 3rd P XM	(1,148)
2015 Budget	**7,340**
EKPC	(243)
OSS RTO/Interco XM	261
NL RTO/Interco & 3rd P XM	(130)
2016 Plan	**7,228**
EKPC	107
OSS RTO/Interco XM	(365)
NL RTO/Interco & 3rd P XM	155
2017 Plan	**7,125**
EKPC	70
OSS RTO/Interco XM	(345)
NL RTO/Interco & 3rd P XM	151
Industrial Coal Sales	16
2018 Plan	**7,017**
EKPC	71
OSS RTO/Interco XM	258
NL RTO/Interco & 3rd P XM	82
Industrial Coal Sales	17
2019 Plan	**7,445**

LG&E KU
PPL companies

2014-2019
Headcount progression

2014 Headcount (As of July 2014) excludes interns	**63**
Generation Planning backfill	1
2014 Headcount FC - Year End	**64**
Fuels Early Hire (January)	1
Fuels Retirement (July)	-1
2015 Headcount Budget	**64**
Generation Planning retirement	-1
2016 Headcount Plan	**63**
2017 Headcount Plan	**63**
Fuels Early Hire (January)	1
Fuels Retirement (July)	-1
2018 Headcount Plan	**63**
2019 Headcount Plan	**63**

PPL companies

Headcount & Employee Expense

2014-2019 Headcount

Business Unit Name	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Total Full Time & Part Time Headcount (without interns)	64	64	63	63	63	63

Employee Related Expenses	2014	2015	2016	2017	2018	2019
1.) Training & Development	$112,949	$106,089	$106,152	$108,264	$109,028	$110,688
2.) Travel	$119,383	$100,348	$102,360	$104,400	$106,488	$108,618
3.) Meals and Expenses	$164,442	$50,312	$51,284	$52,268	$53,313	$54,379
TOTAL	**$396,774**	**$256,749**	**$259,796**	**$264,932**	**$268,829**	**$273,685**
Average Employee Expense per number of employees	**$6,200**	**$4,012**	**$4,124**	**$4,205**	**$4,267**	**$4,344**

PPL companies

PPL companies

CFO Organization

2015 Business Plan

September 17, 2014

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Plan Highlights

- CFO budget is primarily labor costs (~71% of total annual budget).
  - *Employee Opinion Survey suggests resources are sufficient.*
  - *No headcount increases in Plan.*
  - *Reduction of 2 in 2017 for Operations Forecast & Budgeting as construction moderates.*
- Audit, bank and insurance fees comprise approximately 22% of total annual costs.
  - *Cost estimates based on contractual rates and projected activity.*
- The remaining O&M budget is approximately $1.3 Million.
- Capital to support planned upgrades for CFO systems is budgeted as part of the Information Technology centralized five year plan.

Major Assumptions

- Workforce maintained at 142 full-time, 2 part-time, and 11 interns.
- Labor escalations for plan years based on market guidance of 3% per year.
- Non-labor costs based on contractual or expected increases or escalated at 2% increase per year.

PPL companies

Financial Review – Prior Plan to Expectation Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OPEX (O&M and BTL):					
Prior Plan Amount	19,452	19,870	20,517	21,040	21,566
Adjustments/Transfers:					
Direct PPL Charges from Corporate	353	362	372	382	393
Rating Agency Fees from Corporate	80	80	80	80	80
Bank Fees for Smart Safes & Check Scanners (From Customer Services)	55	56	57	58	59
BP Efficiency Savings	(482)	(505)	(478)	(170)	(138)
Current Plan Expectation	19,458	19,864	20,548	21,390	21,960
Drivers:					
Bank Fees (increased fees)	424	384	320	311	361
Retirements & Labor Costs	-	-	(100)	(337)	(381)
Consulting & External Fees			(209)	(247)	(148)
Other	3	(54)	(39)	(42)	(30)
Current Plan	19,886	20,193	20,520	21,075	21,762
Variance	(428)	(330)	28	315	198

LG&E KU
PPL companies

Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan	2014 - 2019 CAGR
O&M Expenses Only:								
Labor	13,137	14,016	14,194	14,545	14,790	15,284	15,706	
Audit Fees	1,591	1,665	1,716	1,716	1,716	1,716	1,785	
Bank Fees	967	1,248	1,835	1,818	1,907	1,928	2,009	
Insurance Management Fee	658	787	806	831	846	861	877	
Training, Travel & Meals	339	593	558	552	544	553	563	
Software Maintenance Fees	49	56	275	284	294	304	315	
Outside Services	427	273	131	72	42	43	114	
Other	454	273	318	321	325	330	335	
Subtotal O&M Expense	17,622	18,912	19,832	20,139	20,465	21,020	21,705	2.8%
Other Income/Expense:								
Labor	1							
Contributions	22	37	39	39	40	40	41	
Employee Recognition & Meals	25	14	14	15	15	15	15	
Other	5							
Total OIE / BTL Expense	53	51	54	54	54	55	57	2.1%
Total OPEX	17,675	18,963	19,886	20,193	20,520	21,075	21,762	2.8%

PPL companies

Financial Performance

2013-2019 Headcount

Department	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Controller	55	55	55	55	55	55	55
Audit Services	14	14	14	14	14	14	14
Corporate Tax & Payroll	16	16	16	16	16	16	16
Financial Plan & Analysis	15	15	15	15	15	15	15
Treasurer	16	16	16	16	16	16	16
Dir Ops Bud & Forecast	26	26	26	26	24	24	24
CFO	2	2	2	2	2	2	2
TOTAL	144	144	144	144	142	142	142
From 2014 Business Plan		144	144	144			
Variance to 2014 Business Plan		0	0	0			

Year to Year Increases (Decreases)	2014	2015	2016	2017	2018	2019
1.) Maintenance /Operational						
2.) Compliance – NERC, FERC, CIP, etc.						
3.) EPA/Environmental						
4.) Administrative/Corporate				(2)		
TOTAL	0	0	0	(2)	0	0

PPL companies

Plan Risks

- Integration of primary system changes within planning window and their impact on existing processes (PeopleSoft Time and Labor, PowerPlant, Oracle, etc.).
- Maintaining flat staffing levels allow for limited resources available for special projects (i.e. new initiatives, future rate cases).
- Planned employee retirements in next few years place greater emphasis on knowledge transfer and effective timing of staffing changes.

Appendix

2013-2019
Year over Year Walk Forward
OPEX and Other Expense

2013 Actual	17,675
Labor	879
Bank Fees	281
Tuition, Education, Travel & Meals	254
Outside Services	(155)
Other	29
2014 FC	18,963
Labor	178
Bank Fees	587
Software Maintenance	218
Other	(60)
2015 Budget	19,886
Labor	351
Outside Services	(59)
Other	15
2016 Plan	20,193
Labor	245
Other	82
2017 Plan	20,520
Labor	493
Other	62
2018 Plan	21,075
Labor	423
Bank Fees	81
Audit Fees	69
Other	114
2019 Plan	21,762

PPL companies

2014-2019
Headcount progression

2014 Headcount (as of July 2014)	143
Accounting Analyst Position Open in Controller	1
2014 Headcount FC - Year End	144
2015 Headcount Budget	144
2016 Headcount Plan	144
Retirements Ops Budgeting & Forecasting	-2
2017 Headcount Plan	142
2018 Headcount Plan	142
2019 Headcount Plan	142

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Headcount & Employee Expense

2014-2019 Headcount

Business Unit Name	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Total Full Time & Part Time Headcount (without interns)	144	144	144	142	142	142

Employee Related Expenses	2014	2015	2016	2017	2018	2019
1.) Training & Development	$388,959	$342,600	$342,121	$331,362	$335,965	$342,088
2.) Travel	$139,821	$124,430	$117,907	$119,413	$121,801	$124,237
3.) Meals and Expenses	$63,541	$90,987	$92,053	$93,174	$95,038	$96,939
4.) Employee Recognition	$14,382	$14,306	$14,568	$14,835	$15,132	$15,435
5.) Employee Dues and Memberships	$33,971	$42,530	$43,063	$44,104	$44,986	$45,886
TOTAL	**$640,674**	**$614,853**	**$609,712**	**$602,888**	**$612,922**	**$624,585**
Average Employee Expense per number of employees	**$ 4,449**	**$ 4,270**	**$ 4,234**	**$ 4,246**	**$ 4,316**	**$ 4,398**

PPL companies

PPL companies

Chief Administrative Officer

2015 Business Plan

September 17, 2014

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PPL companies

Plan Highlights

- The 2015 Chief Administrative Officer O&M budget submitted for the 2015 Business Plan is $107.2 million. The current business plan for 2015 is flat to the Business Plan expectation due to overall CAO budget cuts.
  - *Headcount remained flat to forecast through 2017 and growth was reduced in other areas to meet expectation.*

- The 2015 CAO Capital budget is $39.3 million and is $6.8 million lower than the adjusted 2014 Business Plan. The decrease is due primarily to the CCS upgrade.

PPL companies

Major Assumptions

Information Technology

- Major Initiatives
  - *Roughly one third of the 5 year capital plan (approximately $70M) represents 10 business initiatives (including $23M for CCS and $14M for GIS).*
  - *A significant number of IT resources are tied to these capital projects. Approximately 47 employees at risk to capital which is consistent with the current trend.*
- Safety & Regulatory
  - *Increased regulatory scrutiny at FERC, NERC and SERC as it relates to Critical Infrastructure Protection (CIP) and cyber security will drive the need for increased spending for both labor and information technology solutions to meet compliance requirements. Resource requirements for impact of CIP version 5 are still being assessed and are not included in the plan.*

PPL companies

Major Assumptions

Information Technology

- Business Reliance on Technology
  - *Business reliance on information technology services to conduct day to day operations continues to expand. Due to increased regulatory requirements, more business processes are moving towards automation.*
  - *This trend means that 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.*
  - *Increased reliance on technology is leading to increased storage, maintenance and support costs which are reflected in the plan.*

Major Assumptions

Information Technology

- Cyber Security Threats
  - *IT Security threats and data protection issues continue to increase. These threats are becoming even more sophisticated and difficult to overcome. Continued investment in protective and preventive measures to reduce these threats are required and included in the plan.*

- Customer Experience
  - *As our primary interface with our customers, the CCS system will require additional upgrades and enhancements to continue to meet customer and business expectations. This will include release upgrades to the SAP applications and hardware refresh and expansion.*
  - *Continued efforts to support the customer experience initiative with related capital projects such as call center technology improvements, bill presentation and customer communication preferences.*
  - *Rate Case submissions will continue to occur on a regular basis requiring updates to the CCS system and customer billing.*

PPL companies

Major Assumptions

Information Technology

- Advances in New Technologies
  - *Technology continues to advance at an ever increasing pace. New technologies first introduced in the consumer space are making their way into the enterprise. This includes everything from smart phones to tablet PCs (iPads) to social media.*
  - *Leveraging these new technologies will be a major differentiator for productivity and customer satisfaction.*
  - *The current plans include the deployment of many of these new technologies such as Mobility, Virtual Desktop technology, Unified Communications and Collaboration tools, Business Intelligence and others.*
  - *Plans include working closely with the business to determine which of these technologies can deliver the greatest benefit.*

Major Assumptions

General Counsel

- Legal
  - *The Outside Counsel budget is consistent with current forecast levels.*
  - *Hourly rates of outside providers will not materially increase.*
  - *No significant unexpected developments in pending regulatory or litigation matters and no new material regulatory or litigation claims are assumed in plan.*
  - *Environmental and regulatory litigation will continue to put pressure on budget.*
- Corporate Communications
  - *Maintaining positive brand image in light of increased activities by national and local environmental activists will require additional education and communication measures with key stakeholders.*
  - *Increased Energy Education efforts will require support through targeted communications, advertising and increased sponsorship activation.*
  - *The large number of construction projects and rate pressures will continue to require increased communications.*

PPL companies

Major Assumptions

General Counsel

- Corporate Responsibility
  - *Nonprofit organizations will continue to experience financial challenges.*
  - *Elected officials and general public expectations of corporate community involvement will increase.*
  - *Several key fundraising initiatives are on the horizon:*
    - *K-12 and higher education initiatives*
    - *Public parks and green space initiatives*
    - *Performing arts fundraising initiatives*
  - *Rate case filing and aftermath will require community visibility, enhancement of current community partnerships and development of new partnerships.*
  - *Criticism and scrutiny from environmental groups will require strategic community relations plans.*
  - *Focused community relations strategy needed to address anticipated customer concerns regarding new Louisville Metro franchise agreement implementation.*
  - *Innovative strategies will be needed to address the level of low income customer dissatisfaction.*

Major Assumptions

General Counsel

- Compliance
  - *No material change in current role.*
  - *No new significant enforcement issues.*
  - *Increased emphasis on cyber security.*
  - *Implementation of CIP version 5.*
  - *NERC Reliability Assurance Initiative is still being finalized and could impact resources.*

Major Assumptions

General Counsel

- External Affairs
  - *Increased legislative and regulatory activity by local, state and federal governmental entities affecting the company's activities in the operational, regulatory and environmental areas.*
  - *Pressure by local, state and federal governmental entities upon the company to use its monopolistic status to increase governmental revenues.*
  - *Public comparison of:*
    - Levels of engagement and contributions with and to advocacy groups
    - PPL and LG&E/KU legislative and regulatory positions on various issues

Major Assumptions

General Counsel

- Federal Regulation & Policy
  - *Uncertain implementation path of Order 1000 regional/interregional transmission planning and cost allocation rules.*
  - *Uncertain policy direction arising from the transient nature of the FERC chair over the next several months, the increasing lack of consensus among commissioners and the appointment of a new commissioner.*
  - *Increased pressure on the company to disclose more information regarding how rates are calculated.*
  - *Increased pressure to impose an RTO type model on transmission services.*
  - *Heightened enforcement focus upon the ascendancy to the chair of the new chairman in 2015.*

PPL companies

Major Assumptions

General Counsel

- State Regulation & Rates
  - *Filing of two base rate cases for LG&E and KU in Kentucky.*
  - *Filing of three base rate cases for KU in Virginia.*
  - *Revise the formula rates for FERC wholesale municipal and OATT customers.*
  - *One or more CPCN proceedings for generation facilities.*
  - *Filing of new and enhanced DSM/EE programs.*
  - *Filing of new ECR plans to comply with air regulations.*
  - *Filing of Integrated Resource Plan.*

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PPL companies

Major Assumptions

General Counsel

- Environmental
  - *Coal combustion residuals regulations will likely require closure of all generating station ash ponds.*
  - *Permitting activity will increase significantly and more time required to obtain environmental permits.*
  - *Most all environmental permits associated with coal will be challenged by environmental groups.*
  - *New Ozone NAAQS expected for proposal this year will likely result in significant portion of KY becoming non-attainment.*
  - *Greenhouse Gas regulations for existing units will likely require additional gas-fired generation and less coal.*

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PPL companies

Major Assumptions

Human Resources

- Current and potential Federal legislative initiatives could significantly affect the existing landscape and costs associated with virtually every aspect of the workforce (benefits, compensation, union relations, safety, etc.).
- Wellness must continue to evolve as a means of containing healthcare costs.
- The pace and complexity of regulatory compliance will continue to escalate.
- Competition for talent will require more non-traditional sourcing.
- Capital spend within the plan is based on the need to automate certain HR systems.
- Retirement-based attrition will continue to put demands on staffing and development.
- We must continue to find balance between the regular workforce and contractors on certain key functions.

Major Assumptions

Supply Chain

- Detailed long range procurement plans are in place.
- Proactive engagement with the PPL Supply Chain is planned in the T&D and Corporate areas, but the nature and magnitude of the engagement is unknown at this point due to the change in leadership and go-forward leadership philosophy.
- Known retirements occurring in early 2016 will be filled by a combination of current internal resources and internal hiring.
- Several initiatives have been identified and/or being implemented that will result in efficiency improvements to the way paper invoices are being received and processed through AP.
- Active engagement with the UK and UL Schools of Business will continue.

Financial Review – Prior Plan to Plan Expectation Reconciliation
CAO Consolidated ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OPEX (O&M and BTL):					
Prior Plan Amount	108,696	110,995	117,150	119,463	122,457
Adjustments/Transfers:					
IT HW/SW MTCE	1,680	1,764	1,852	1,945	2,042
BP Efficiency Savings	(2,994)	(3,506)	(3,873)	(1,364)	(1,344)
Software Transfers from ES&A	237	242	247	252	257
HR transfer to Safety and Security	(255)	(261)	(267)	(273)	(279)
Current Plan Expectation	107,364	109,234	115,109	120,022	123,133

Financial Performance – OPEX

CAO Consolidated

2013-2019 O&M and Other Income/Expenses
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M Expenses Only:							
Labor	41,683	46,569	50,661	52,267	53,626	56,288	58,864
HW/SW Maintenance	14,733	16,181	19,096	20,412	21,639	22,776	24,093
Outside Counsel	5,987	7,997	8,092	8,484	8,908	9,353	9,821
Other O/S Services	7,314	8,488	7,825	7,548	8,421	7,964	8,066
Training, Travel, & Meals	1,647	2,516	2,276	2,304	2,368	2,415	2,440
Dues & Subscriptions	2,442	2,705	3,106	3,284	3,448	3,656	3,884
Advertising	1,295	1,639	1,404	1,439	1,540	1,615	1,656
Rate Case Amortization	1,685	1,084	1,648	1,232	2,378	2,336	2,895
Other Non-Labor	8,379	10,935	8,252	8,090	7,869	7,956	7,889
Subtotal O&M Expense	85,166	98,114	102,361	105,059	110,197	114,360	119,607
Other Income/Expense*	5,651	5,675	4,836	5,043	5,228	5,306	5,448
* (see OIE slide for detail)							
Total OPEX	90,817	103,789	107,197	110,102	115,425	119,666	125,056
Current Plan Expectation			107,364	109,234	115,109	120,022	123,133
Variance to Plan			167	(868)	(315)	355	(1,922)

Financial Performance – OPEX

CAO Consolidated

2013-2019 Other Income/Expenses (incl. BTL)
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OIE/BTL Expenses Only:							
Labor	1,039	1,031	528	544	553	569	586
Employee Recognition	236	357	416	486	468	464	495
Contributions	1,876	2,291	2,122	2,194	2,358	2,389	2,444
Training, Travel, & Meals	589	509	371	382	387	395	403
Other Non Labor	1,911	1,488	1,399	1,438	1,462	1,489	1,520
Total OIE / BTL Expense	5,651	5,675	4,836	5,043	5,228	5,306	5,448

PPL companies

2013-2019 Capital Breakdown (w COR) – Accrual Basis
CAO Consolidated ($000)

Project	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Information Technology							
SAP CRM/ECC Upgrade	-	-	-	*17,200*	*5,800*	-	-
Smallworld GIS Upgrade	-	-	-	-	*3,324*	*4,749*	*5,927*
SAP CRM/ECC Enhancement	-	-	*500*	*500*	*500*	*3,000*	*4,000*
Cisco UC&C	*3,840*	*2,119*	*962*	-	-	-	-
Oracle Financials Upgrade	-	-	-	*3,078*	*3,762*	-	-
NorthEast KY Transport Buildout	-	-	-	-	*1,805*	*1,805*	*1,805*
Work Mgmt System	*3,087*	*1,160*	-	-	-	-	-
SAN Capacity Expansion	-	-	*1,057*	*952*	*255*	*967*	*1,000*
Mobile Radio System Replacement	-	-	-	*4,000*	-	-	-
OTN Core Rings	-	-	*2,090*	*1,900*	-	-	-
Oracle Licenses	*3,959*	-	-	-	-	-	-
Enterprise Storage System Refresh	-	-	-	-	*3,952*	-	-
Replace Fiber Reach Nodes	*1,403*	*1,274*	*950*	-	-	-	-
Ventyx Mobile Upgrade	-	*653*	*2,236*	*700*	-	-	-
Ventyx Mobile Upgrade	-	*653*	*2,236*	*700*	-	-	-
Server Hardware Refresh	-	-	*575*	*510*	*772*	*510*	*510*
Transmission Lines Work Management	-	-	-	*1,250*	*1,250*	-	-
Access Switch Rotation	-	-	*390*	*500*	*500*	*500*	*500*
Mobile Dispatch for ARM	-	-	-	*500*	*1,750*	-	-
Refresh/Replace VDI Infrastrcuture	-	-	-	-	*2,185*	-	-
OTN Extension EKY Ring	-	-	-	-	-	-	*1,710*
Design Tool Replacement (WIM)	-	-	*1,700*	-	-	-	-
IVR - Major upgrades/changes	-	-	-	-	*1,425*	-	-
Oracle Network Mgmt System	-	-	-	-	-	*1,425*	-
SAN Switch Refresh	-	-	-	-	-	-	*1,400*
Analog Sunset	-	-	*266*	*266*	*266*	*266*	*266*

PPL companies

2013-2019 Capital Breakdown (w COR) – Accrual Basis CAO Consolidated ($000)

Project	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Information Technology							
Call Recording Upgrade	-	-	-	-	-	*475*	*823*
PS 9.2 Upgrade	-	-	-	*604*	*649*	-	-
Expand Responsive Design of My Accoun	-	-	*250*	*250*	*250*	*250*	*250*
Purchase/Rebuild Radio Sites	-	-	*300*	*150*	*219*	*300*	*250*
LogRhythm Hardware Refresh	-	-	-	*222*	-	-	*995*
CERUS IV	-	-	-	*400*	*400*	*400*	-
Customer Preference Portal - SMS, email,	-	-	-	*300*	*300*	*300*	*300*
WMS Work Management System Upgrad	-	-	-	-	-	-	*1,200*
Backup Capacity Expansion	-	-	*200*	*200*	*225*	*225*	*225*
Outside Cable Plant	-	-	*200*	*200*	*200*	*200*	*200*
Cascade Biennial Technology/Compliance	-	-	-	*500*	-	*500*	-
Customer Bill Redesign / Bill Print Tool	-	-	*500*	*500*	-	-	-
Maximo Upgrade	-	-	-	-	-	*500*	*500*
Other	*25,475*	*29,339*	*23,181*	*19,819*	*16,819*	*19,045*	*17,561*
Supply Chain							
Danville Trans Pole Yard	*738*	*1*	-	-	-	-	-
Lexington Stone Rd Pole Racks	-	*270*	-	-	-	-	-
Danville Pole Racks	*231*	*(0)*	-	-	-	-	-
Auburndale Plating Storage	-	-	-	*100*	*100*	-	-
Other	*209*	*306*	*600*	*430*	*345*	*317*	*358*
Human Resources							
HR Planning	-	-	*938*	-	-	-	-
Recruiting System Impl	*65*	*253*	-	-	-	-	-
HR Cap Equip Improvmnts LGE	-	-	*20*	*20*	*20*	*20*	*20*
General Counsel							
Environmental Equipment LGE	-	*101*	*100*	*100*	*100*	*99*	*100*
	39,007	*36,129*	*39,251*	*55,851*	*47,173*	*35,853*	*39,899*

2015-2019
Capital Reconciliation (w COR) –Accrual Basis
CAO Consolidated ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Prior Plan	46,002	42,598	40,775	39,692	29,943
Changes:					
CCS Upgrade	(10,340)	13,440	1,600	-	-
CCS Enhancements	-	-	-	(1,700)	4,000
SAP AMI Implementation	(1,880)	(5,640)	-	-	-
OTN Core Rings	2,090	1,900	-	-	1,710
Ventyx Mobile Upgrade	2,236	700	-	-	-
GIS/Smallworld	-	-	-	(1)	5,927
Other IT	185	2,833	4,678	(2,303)	(1,759)
General Counsel Total	-	-	-	(1)	100
Human Resources Total	958	20	20	20	(380)
Supply Chain Total	-	-	100	145	358
Current Plan	$ 39,251	$ 55,851	$ 47,173	$ 35,853	$ 39,899

PPL companies

Financial Performance

CAO Consolidated

2013-2019 Headcount (excluding interns)

Department	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
CAO	2	2	2	2	2	2	2
General Counsel	93	99	100	100	100	100	100
Human Resources	54	54	54	54	54	54	54
Supply Chain	50	51	51	52	52	52	52
IT	286	311	311	311	311	318	326
TOTAL	485	517	518	519	519	526	534
From 2014 Business Plan		516	524	526			
Variance to 2014 Business Plan		1	-6	-7			

Year to Year Increases (Decreases)	2014	2015	2016	2017	2018	2019
1.) Maintenance /Operational	0	0	0	0	0	0
2.) Compliance – NERC, FERC, CIP, etc.	5	0	0	0	1	0
3.) EPA/Environmental	1	0	0	0	0	0
4.) Administrative/Corporate	26	1	1	0	6	8
TOTAL	32	1	1	0	7	8

PPL companies

Plan Risks

Information Technology

- Resource requirements for impact of CIP version 5 are still being assessed and not included in the plan.
- Available resources have been allocated to required or high risk capital projects. A significant number of projects identified through strategic planning were unfunded.
- Acquiring skilled IT resources will continue to be a challenge for us and the rest of the industry.
- Approximately 47 employees at risk to capital labor; $6.8m each year of the plan. Any subsequent changes to the capital plan may adversely impact O&M.
- Project assessments and software maintenance contract renewals for significant systems costs may be materially higher than planned (e.g. Oracle).
- Increased capital and O&M costs due to industry regulatory requirements.
- Planned levels of spend do not include unplanned business initiatives that may have an IT O&M impact.

Plan Risks

General Counsel

- Legal
  - *New environmental regulations and third-party challenges will continue to require extraordinary legal review and input.*
  - *The Company becomes involved in a significant unanticipated legal dispute.*
  - *Intensity of litigation with respect to a pending matter may significantly increase.*

- Corporate Communications
  - *Given increased ECR spending, planned rate cases and cost associated with the new EPA regulations, customer bills will continue to increase, potentially resulting in lower customer satisfaction levels.*
  - *National and local environmental groups will continue to threaten the company's brand.*

PPL companies

Plan Risks

General Counsel

- Corporate Responsibility
  - *Weather uncertainties and/or natural disasters may necessitate new levels of assistance to agencies addressing the needs of challenged customers.*
  - *Unfavorable legal or regulatory result may require focused community relations strategy.*
- Compliance
  - *NERC Reliability Standards, including Cyber Security Standards, are likely to be revised and affect resources.*
  - *Extraordinary workload anticipated due to efforts to implement new CIP version 5 requirements and revise or expand certain compliance programs.*

Plan Risks

General Counsel

- Federal Regulation & Policy
  - *Unreasonable requirements for acceptance of FERC 1000 compliance filings.*
  - *Greater socialization of transmission costs across the entire region.*
  - *Increased tension between state and federal regulators with respect to cost recovery.*
  - *New rules and regulations promulgated by EPA and FERC.*
  - *Imposition of new efficiency and demand response pricing rules that would modify existing commercial and regulatory arrangements.*
  - *Increased regulatory and economic pressure to join an RTO.*

PPL companies

Plan Risks

General Counsel

- External Affairs
  - *Upward pressure on customer's electric rates due to increased capital expenditures for pollution control and base load generation construction. Environmental, energy efficiency and renewable portfolio standards legislation and Federal EPA regulations place substantial compliance costs on the company and its customers.*
  - *Local, State and Federal budget shortfalls result in increased efforts to raise revenue through surcharges on the customer electric bill and increased corporate fees and taxes.*
  - *Political environment at the federal and state level becomes increasingly more challenging.*
  - *Push by industrials for limited wheeling.*
  - *Increased efforts to maintain or increase subsidies for solar customers.*

Plan Risks

General Counsel

- State Regulation & Rates
  - *Commission and intervenor sensitivity to rising costs.*
  - *Failure to get timely regulatory approvals for generation and transmission investment could put customer service and utility economics at risk.*
  - *Legislation that changes the regulatory structure (e.g. limited wheeling for industrials).*
  - *Increased scope and diversity of intervenors in proceedings.*
  - *Increased efforts to maintain or increase subsidies for distributed generation customers.*

Plan Risks

General Counsel

- Environmental
  - *Water discharge permits limits could be lower than expected.*
  - *The requirements for closure of existing ash ponds could be greater than predicted.*
  - *Potential for need of addition of SCRs on coal-fired units (Ghent 2, Mill Creek 1 and 2).*
  - *Additional permitting activities associated with new gas-fired generation.*

PPL companies

Plan Risks

Human Resources

- Economic pressures and impact on Human Resource management.
- Effects of possible Federal legislation relating to benefits, compensation, labor, safety and taxation.
- Staffing expenses and resources could increase due to the need to expand the potential hiring base due to attrition and the increase in planned retirements.

Plan Risks

Supply Chain

- Workforce demographics will continue to challenge both our short and long term staffing strategies.
- While all major work is covered by consolidated multi-year agreements, non-routine (project) work not yet known nor included in the existing Procurement Plans could require the need for temporary sourcing resources.

Appendix

PPL companies

Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses Information Technology ($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M Expenses Only:							
Labor	22,728	26,154	29,029	29,982	30,766	32,691	34,590
HW/SW Maintenance	14,733	16,181	19,096	20,412	21,639	22,776	24,093
O/S Services	4,458	5,050	4,082	3,747	3,822	3,895	3,970
Training, Travel, & Meals	730	1,141	993	1,016	1,037	1,058	1,079
Dues & Subscriptions	35	40	49	50	51	52	53
Other Non-Labor	4,187	6,509	4,587	4,600	4,621	4,653	4,533
Subtotal O&M Expense	46,872	55,075	57,837	59,807	61,937	65,125	68,317
Other Income/Expense							
Employee Recognition	11	66	74	75	77	78	80
Contributions	2	3	3	3	3	3	3
Other Non-Labor	124	7	0	-	-	-	-
Subtotal Other Income/Expense	137	75	76	78	79	81	83
Total OPEX	47,009	55,150	57,914	59,885	62,016	65,206	68,400

PPL companies

2015-2019 O&M / Other Expense Reconciliation
Information Technology ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Plan Expectation	57,945	59,810	62,032	65,697	67,431
Drivers:					
IT HW/SW MTCE	(157)	381	762	1,093	1,920
Labor	498	504	123	(237)	649
Outside Services	(176)	(568)	(569)	(740)	(763)
Fee, Licenses and Permits	(195)	(198)	(201)	(212)	(217)
Other Non Labor	(3)	(44)	(131)	(394)	(621)
Current Plan	57,914	59,885	62,016	65,206	68,400
Expectation Variance-Fav / (Unfav)	32	(75)	16	491	(969)

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PPL companies

2013-2019 Year over Year Walk Forward
OPEX and Other Expense
Information Technology ($000)

2013 Actual	**47,009**
Labor	3,392
HW/SW Maintenance	2,845
O/S Services	592
Other Non Labor	1,312
2014 FC	**55,150**
Labor	2,826
HW/SW Maintenance	1,589
O/S Services	(968)
Other Non Labor	(684)
2015 Budget	**57,914**
Labor	950
HW/SW Maintenance	1,315
O/S Services	(336)
Other Non Labor	41
2016 Plan	**59,885**
Labor	780
HW/SW Maintenance	1,228
Other Non Labor	123
2017 Plan	**62,016**
Labor	1,921
HW/SW Maintenance	1,137
Other Non Labor	132
2018 Plan	**65,206**
Labor	1,895
HW/SW Maintenance	1,317
Other Non Labor	(18)
2019 Plan	**68,400**

PPL companies

2014-2019
Headcount Progression (excluding interns)
Information Technology

2014 Headcount (As of July 2014)	**292**
Telecom Engineer	2
Telecom Technician (Compliance)	2
Network Engineer (2 Compliance)	4
Database Admin	1
Security Analyst (1 Compliance)	2
BI Support	1
.Net and Mobile	1
Programmer Analyst	4
Service Desk Support analyst	1
Workstation Technician	1
2014 Headcount FC - Year End	**311**
2015 Headcount Budget	**311**
2016 Headcount Plan	**311**
2017 Headcount Plan	**311**
.Net and Mobile	2
CIP Security Analyst	1
Project Mgmt Leader	1
Telecom Engineer	1
Network Engineer	1
Infrastucture Computer Operator	1
2018 Headcount Plan	**318**
Telecom	2
Network Engineer	2
.Net and Mobile	1
BI Support	1
Customer Service	1
Workstation Technician	1
2019 Headcount Plan	**326**

PPL companies

Headcount & Employee Expense

Information Technology ($)

2014-2019 Headcount (excluding interns)

Business Unit Name	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Total Full Time & Part Time Headcount (without interns)	311	311	311	311	318	326

Employee Related Expenses	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
1.) Training & Development	$659,147	$661,159	$677,622	$691,174	$704,999	$719,098
2.) Travel	$364,170	$325,402	$327,346	$329,329	$331,352	$333,415
3.) Meals and Expenses	$237,269	$175,325	$177,691	$180,106	$182,568	$185,080
4.) Employee Recognition	$65,521	$73,830	$75,307	$76,813	$78,349	$79,916
5.) Employee Dues and Memberships	$24,605	$24,151	$24,634	$25,127	$25,629	$26,142
TOTAL	**$1,350,712**	**$1,259,867**	**$1,282,601**	**$1,302,549**	**$1,322,897**	**$1,343,651**
Avg. Employee Expense per number of employees	**$ 4,343**	**$ 4,051**	**$ 4,124**	**$ 4,188**	**$ 4,160**	**$ 4,122**

PPL companies

Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses
General Counsel ($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M Expenses Only:							
Labor	9,847	10,600	11,582	11,951	12,224	12,614	12,972
Outside Counsel	5,987	7,997	8,092	8,484	8,908	9,353	9,821
O/S Services	2,225	2,617	2,997	3,011	3,661	3,239	3,244
Dues & Subscriptions	2,272	2,576	2,800	2,972	3,130	3,333	3,554
Rate Case Amortization	1,685	1,032	1,648	1,232	2,378	2,336	2,895
Training, Travel, & Meals	554	755	689	706	718	732	747
Other Non-Labor	5,114	5,422	4,723	4,596	4,422	4,557	4,659
Subtotal O&M Expense	27,684	30,999	32,531	32,951	35,440	36,164	37,892
Other Income/Expense							
Labor	1,027	1,031	528	544	553	569	586
Contributions	1,609	2,108	1,976	2,054	2,202	2,252	2,304
Training, Travel, & Meals	305	263	211	218	221	225	230
Employee Recognition	13	12	12	12	13	13	13
Outside Counsel	290	-	0	-	-	-	-
Other	1,040	968	856	887	902	918	938
Subtotal Other Income/Expense	4,284	4,381	3,583	3,716	3,891	3,978	4,071
Total OPEX	31,968	35,380	36,114	36,667	39,331	40,141	41,963

PPL companies

2015-2019 O&M / Other Expense Reconciliation
General Counsel ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Plan Expectation	36,273	35,972	39,243	39,779	40,783
Drivers:					
Rate Case Amortization	(577)	38	(475)	676	1,202
Labor	114	163	40	86	69
Outside Services	42	210	182	268	100
Outside Counsel	208	251	295	104	106
Environmental Fees & Dues	(99)	(270)	(479)	(346)	(197)
Other	154	301	525	(426)	(99)
Current Plan	36,114	36,667	39,331	40,141	41,963
Expectation Variance-Fav / (Unfav)	159	(695)	(88)	(362)	(1,180)

PPL companies

2013-2019 Year over Year Walk Forward
OPEX and Other Expense
General Counsel ($000)

2013 Actual	**31,968**
Outside Counsel & O/S Services	2,112
Contributions	498
Labor	757
Rate Case Amortization	(653)
Other Non Labor	698
2014 FC	**35,380**
Rate Case Amortization	616
Labor	480
Outside Counsel & O/S Services	475
Other Non Labor	(704)
Contributions	(132)
2015 Budget	**36,114**
Rate Case Amortization	(417)
Outside Counsel & O/S Services	406
Labor	385
Other Non Labor	178
2016 Plan	**36,667**
Rate Case Amortization	1,147
Outside Counsel & O/S Services	1,074
Labor	283
Contributions	148
Other Non Labor	13
2017 Plan	**39,331**
Labor	406
Rate Case Amortization	(43)
Other Non Labor	447
2018 Plan	**40,141**
Labor	375
Rate Case Amortization	559
Outside Counsel & O/S Services	473
Other Non Labor	414
2019 Plan	**41,963**

2014-2019
Headcount Progression (excluding interns)
General Counsel

2014 Headcount (As of July 2014)	94
Corporate Events Specialist	1
Corporate Responsibility Manager	1
Compliance Secretary	1
Environmental Schientist/Engineer	1
Environmental Secretary	1
2014 Headcount FC - Year End	99
Rates & Regulatory Analyst	1
2015 Headcount Budget	100
2016 Headcount Plan	100
2017 Headcount Plan	100
2018 Headcount Plan	100
2019 Headcount Plan	100

PPL companies

Headcount & Employee Expense

General Counsel ($)

2014-2019 Headcount (excluding interns)

Business Unit Name	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Total Full Time & Part Time Headcount (without interns)	99	100	100	100	100	100

Employee Related Expenses	2014	2015	2016	2017	2018	2019
1.) Training & Development	$177,393	$128,438	$135,020	$136,665	$139,399	$142,187
2.) Travel	$345,909	$318,832	$319,063	$319,336	$319,111	$318,881
3.) Meals and Expenses	$171,980	$192,024	$193,750	$195,465	$197,694	$199,968
4.) Employee Recognition	$12,272	$12,200	$12,406	$12,618	$12,870	$13,128
5.) Employee Dues and Memberships	$21,128	$49,012	$49,936	$50,874	$51,891	$52,929
TOTAL	**$728,682**	**$700,506**	**$710,175**	**$714,958**	**$720,966**	**$727,093**
Average Employee Expense per number of employees	**$ 7,360**	**$ 7,005**	**$ 7,102**	**$ 7,150**	**$ 7,210**	**$ 7,271**

excludes intiatives that are not employee driven

PPL companies

Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses
Human Resources ($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M Expenses Only:							
Labor	5,424	5,881	6,023	6,164	6,330	6,537	6,727
O/S Services	602	759	690	732	879	770	791
Training, Travel, & Meals	204	403	313	301	328	333	316
Dues & Subscriptions	65	44	173	176	179	183	187
HW/SW Maintenance	28	28	0	-	-	-	-
Other Non-Labor	196	495	224	207	236	228	217
Subtotal O&M Expense	6,519	7,609	7,423	7,580	7,953	8,051	8,238
Other Income/Expense*							
Employee Recognition	207	272	322	390	370	364	394
Contributions	45	99	62	54	69	49	49
Other Non-Labor	36	-	0	-	-	-	0
Subtotal Other Income/Expense	288	370	385	444	439	413	443
Total OPEX	6,807	7,979	7,807	8,024	8,392	8,464	8,681

2015-2019 O&M / Other Expense Reconciliation
Human Resources ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Plan Expectation	7,828	8,006	8,175	8,636	8,860
Drivers:					
Outside Services	-	-	128	(129)	-
Software Maint. Reductions	-	-	-	-	-
Other	(21)	19	90	(43)	(179)
Current Plan	7,807	8,024	8,392	8,464	8,681
Expectation Variance-Fav / (Unfav)	(21)	19	217	(172)	(179)

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2013-2019 Year over Year Walk Forward
OPEX and Other Expense
Human Resources ($000)

2013 Actual	**6,807**
Labor	457
HW/SW Maintenance	210
Training Travel & Meals	199
O/S Services	157
Other Non Labor	150
2014 FC	**7,979**
Labor	142
Training Travel & Meals	(90)
O/S Services	(69)
Other Non Labor	(155)
2015 Budget	**7,807**
Labor	141
Other Non Labor	76
2016 Plan	**8,024**
Labor	167
O/S Services	147
Other Non Labor	54
2017 Plan	**8,392**
Labor	206
O/S Services	(109)
Other Non Labor	(25)
2018 Plan	**8,464**
Labor	191
Other Non Labor	26
2019 Plan	**8,681**

2014-2019
Headcount Progression (excluding interns)
Human Resources

2014 Headcount (As of July 2014)	53
HRIS Business Analyst Open	1
2014 Headcount FC - Year End	54
2015 Headcount Budget	54
2016 Headcount Plan	54
2017 Headcount Plan	54
2018 Headcount Plan	54
2019 Headcount Plan	54

PPL companies

Headcount & Employee Expense

Human Resources ($)

2014-2019 Headcount (excluding interns)

Business Unit Name	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Total Full Time & Part Time Headcount (without interns)	54	54	54	54	54	54

Employee Related Expenses	2014	2015	2016	2017	2018	2019
1.) Training & Development	$160,212	$96,998	$106,720	$107,680	$101,665	$103,714
2.) Travel	$205,806	$158,592	$159,330	$159,880	$160,914	$161,969
3.) Meals and Expenses*	$51,998	$54,754	$54,592	$54,542	$54,595	$54,649
4.) Employee Recognition**	$21,695	$20,004	$23,576	$23,684	$24,158	$24,641
5.) Employee Dues and Memberships	$5,408	$15,638	$15,814	$15,966	$16,285	$16,611
TOTAL	**$445,119**	**$345,986**	**$360,032**	**$361,752**	**$357,617**	**$361,584**
Average Employee Expense per number of employees	**$ 8,243**	**$ 6,407**	**$ 6,667**	**$ 6,699**	**$ 6,623**	**$ 6,696**

*adjusted for Retiree Expenses
**excludes Services Awards

PPL companies

Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses
Supply Chain ($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M Expenses Only:							
Labor	3,053	3,332	3,390	3,513	3,632	3,750	3,859
O/S Services	29	29	16	17	17	17	18
Training, Travel, & Meals	84	118	131	127	130	133	136
Dues & Subscriptions	10	24	26	26	27	27	28
Other Non-Labor	93	113	79	85	86	88	90
Subtotal O&M Expense	3,270	3,616	3,642	3,768	3,892	4,016	4,132
Other Income/Expense							
Employee Recognition	2	2	3	3	3	3	3
Contributions	19	27	26	26	26	27	27
Other	2	-	0	-	-	-	-
Subtotal Other Income/Expense	23	29	29	29	29	30	31
Total OPEX	3,293	3,645	3,672	3,798	3,921	4,046	4,162

2015-2019 O&M / Other Expense Reconciliation
Supply Chain ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Plan Expectation	3,643	3,733	3,908	4,117	4,222
Drivers:					
Other	28	65	13	(70)	(59)
Current Plan	3,672	3,798	3,921	4,046	4,162
Expectation Variance-Fav / (Unfav)	(28)	(65)	(13)	70	59

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2013-2019 Year over Year Walk Forward
OPEX and Other Expense
Supply Chain ($000)

2013 Actual	**3,293**
Labor	279
Training, Travel, & Meals	34
Other Non Labor	39
2014 FC	**3,645**
Labor	58
Other Non Labor	(31)
2015 Budget	**3,672**
Labor	123
Other Non Labor	3
2016 Plan	**3,798**
Labor	119
Other Non Labor	5
2017 Plan	**3,921**
Labor	118
Other Non Labor	7
2018 Plan	**4,046**
Labor	109
Other Non Labor	7
2019 Plan	**4,162**

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PPL companies

2014-2019
Headcount Progression (excluding interns)
Supply Chain

2014 Headcount (As of July 2014)	**50**
Storeroom Specialist London	1
2014 Headcount FC - Year End	**51**
2015 Headcount Budget	**51**
Support Analyst	1
2016 Headcount Plan	**52**
2017 Headcount Plan	**52**
2018 Headcount Plan	**52**
2019 Headcount Plan	**52**

PPL companies

Headcount & Employee Expense

Supply Chain ($)

2014-2019 Headcount (excluding interns)

Business Unit Name	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Total Full Time & Part Time Headcount (without interns)	51	51	52	52	52	52

Employee Related Expenses	2014	2015	2016	2017	2018	2019
1.) Training & Development	$68,772	$80,730	$70,354	$71,716	$68,076	$69,525
2.) Travel	$64,488	$59,532	$59,976	$60,480	$60,833	$61,193
3.) Meals and Expenses	$15,462	$15,828	$15,948	$16,080	$16,263	$16,450
4.) Employee Recognition	$2,040	$3,012	$3,060	$3,120	$3,182	$3,246
5.) Employee Dues and Memberships	$0	$2,664	$2,712	$2,784	$2,840	$2,896
TOTAL	**$150,762**	**$161,766**	**$152,050**	**$154,180**	**$151,195**	**$153,311**
Average Employee Expense per number of employees	**$ 2,956**	**$ 3,172**	**$ 2,924**	**$ 2,965**	**$ 2,908**	**$ 2,948**

PPL companies

2013-2019
Other Balance Sheet Costs
CAO Consolidated ($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Stores Expense							
Labor	1,311	1,269	1,408	1,428	1,451	1,482	1,514
Non labor	802	695	847	887	889	907	925
Total	2,114	1,963	2,256	2,314	2,339	2,389	2,439
WKE							
Labor	9	-	-	-	-	-	-
Non labor	463	250	80	80	80	82	83
Total	471	250	80	80	80	82	83
Regulatory Assets							
Non labor	-	1,850	3,245	2,103	3,113	2,110	3,238
Total	-	1,850	3,245	2,103	3,113	2,110	3,238
Total Other Costs	2,585	4,063	5,581	4,497	5,533	4,580	5,760

LG&E KU

PPL companies

Electric Distribution

2015 Business Plan

September 17, 2014

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Plan Highlights

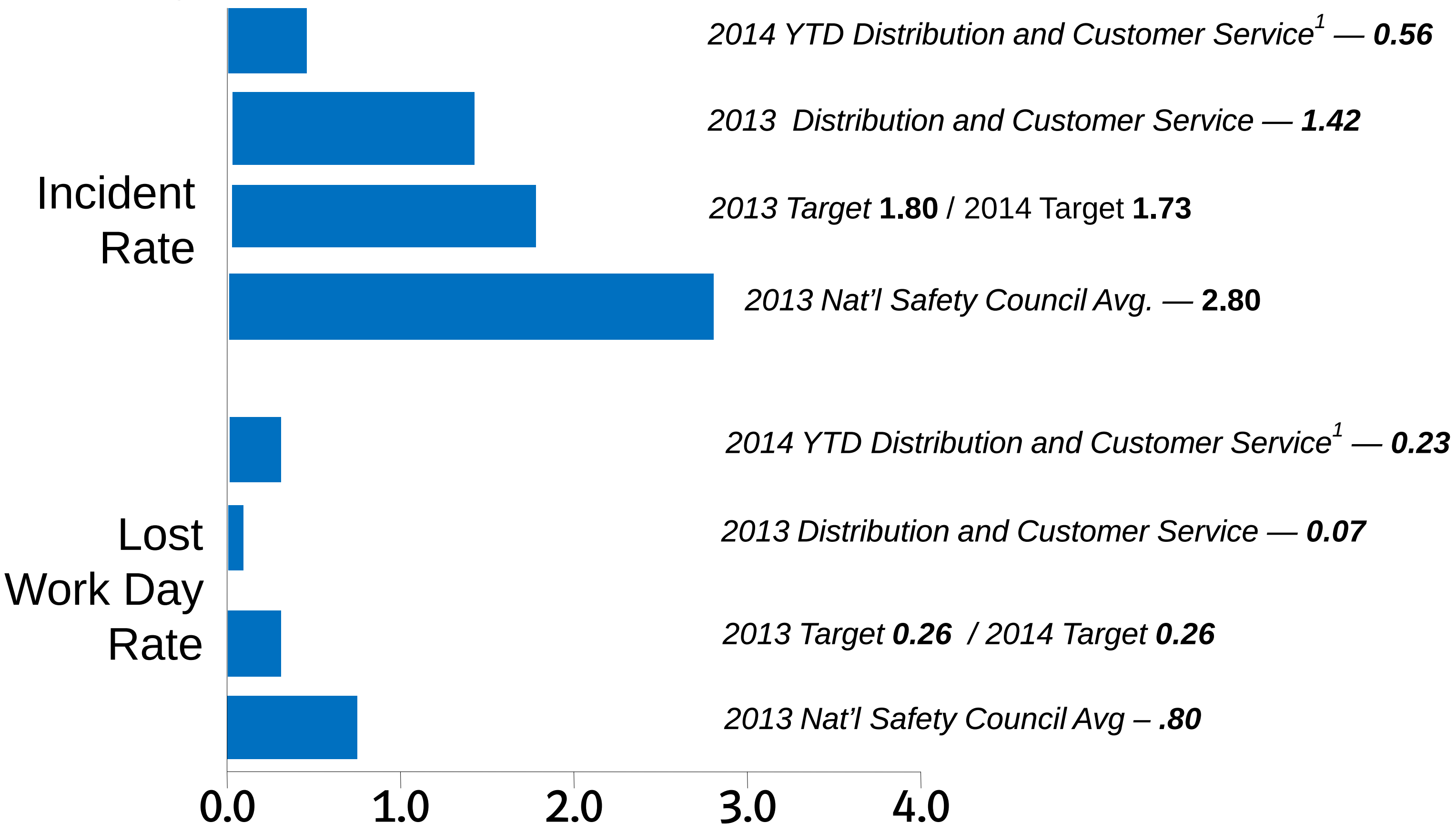
Electric Distribution's Business Plan provides for continued emphasis on the Company's core values of safety and customer satisfaction. Plan funding will continue to provide for safe, reliable and low cost electric service for customers, with priority given to the following:

- Employee, business partner and public safety
- Electric system hardening and protection to improve service reliability
- Technology advancements to enhance business processes, improve operational efficiencies and increase customers' communications options
- Asset replacements to address aging infrastructure
- System enhancements to meet existing and future customer loads and to improve contingency in critical areas of the system
- Construction projects to serve new customers and satisfy customer requested projects
- Maintenance, inspections and operations programs which assure regulatory compliance and operational performance

PPL companies

Plan Highlights

Safety Performance

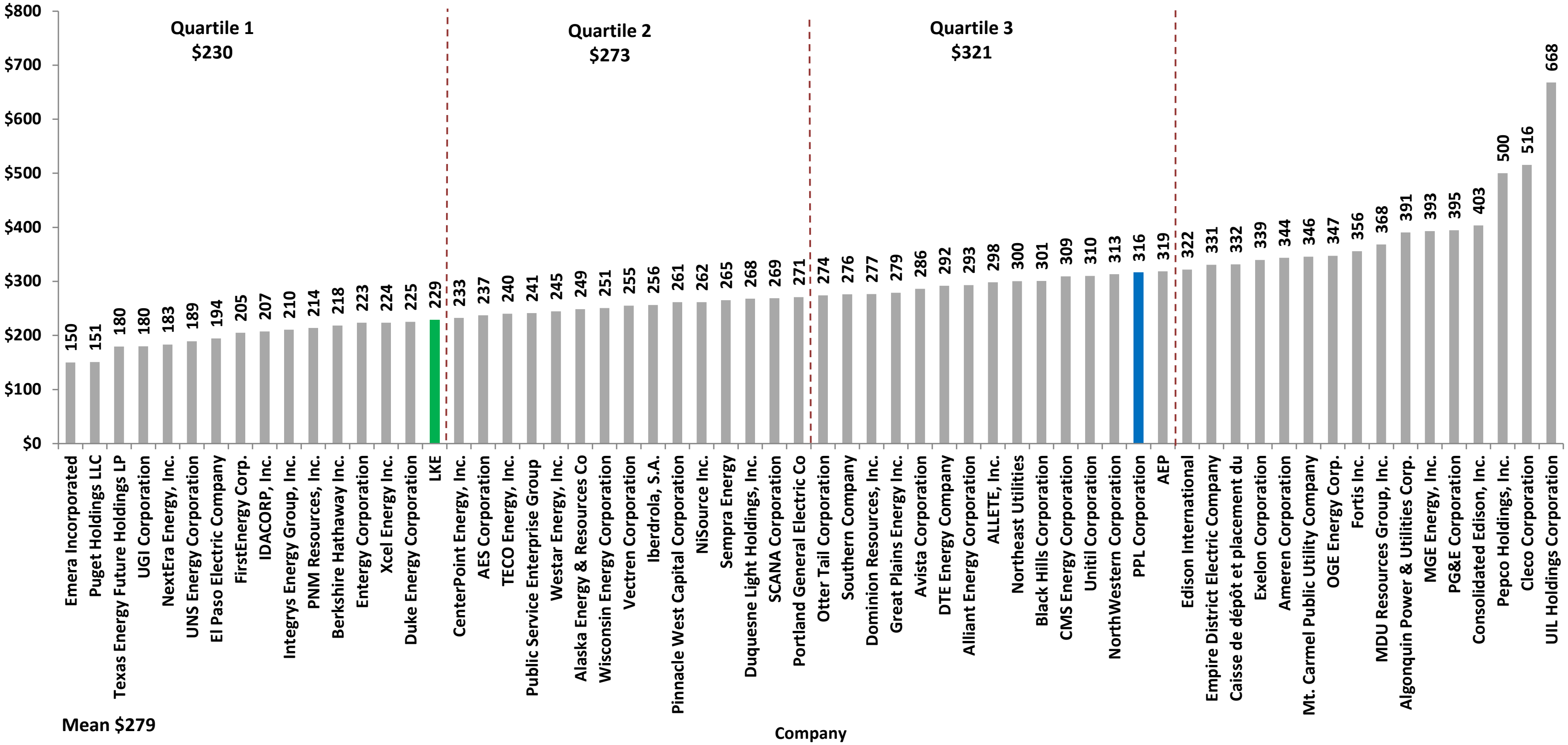


[1] As of July YTD 2014

Plan Highlights

Total DO Electric Cash Cost per Customer Performance

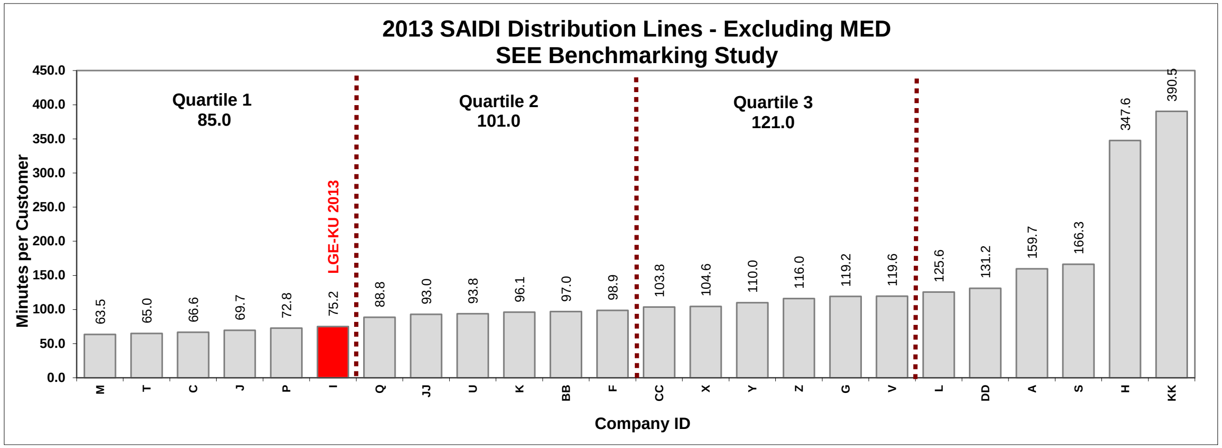
Overall Electric Distribution Expenditures per Customer
FERC Utility Cost Benchmarking – 2013 Data (Electric Only)

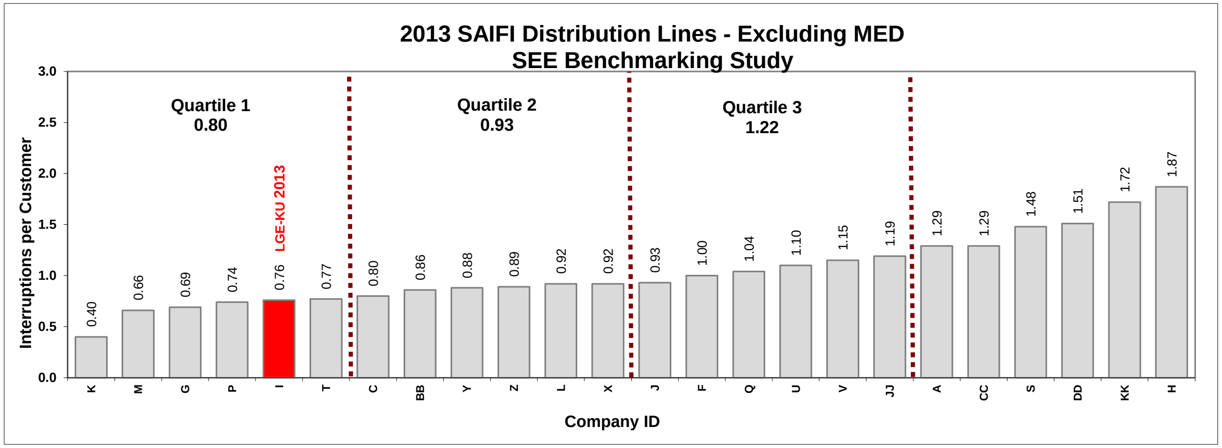


PPL companies

Plan Highlights

Reliability Performance


2013 SAIDI Distribution Lines - Excluding MED
SEE Benchmarking Study


2013 SAIFI Distribution Lines - Excluding MED
SEE Benchmarking Study

PPL companies

Plan Highlights

- Safety and Wellness
  - *Continue commitment to employees, business partners and public safety*
  - *Maintain industry leading performance*
  - *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*
  - *Focus on incident prevention plans and critical danger zones*
  - *Continue to improve motor vehicle safety*
  - *Identify, share and capitalize on industry best practices*
  - *Promote wellness as an aspect of safety*

Plan Highlights

- Customer Experience
  - *Continue to respond to all outage events in an efficient and effective manner, and continue to improve on the accuracy and timeliness of restoration times*
  - *Continue to identify and respond to opportunities to improve reliability performance*
  - *Continue to build on technology which enhances business processes, reduces cycle times, and enhances communications with customers*
  - *Invest in aging infrastructure replacement to continue long term service reliability*
  - *Continue to be responsive to customer requests for new service or infrastructure relocations*
  - *Continue focus on portraying a professional and positive customer image*
  - *Satisfy customer capacity needs*

Plan Highlights

- OPEX
  - *On target in 2014 to achieve 7&5 approved forecast.*
  - *Compounded Annual Growth Rate (CAGR) from 2014-2019 is flat.*
  - *Major Initiatives:*
    - Line Clearance, Hazard Tree Program and Emerald Ash Borer removal
    - Regulatory Inspection and Maintenance Programs
    - Storm and Trouble Response
  - *Major Financial Risks:*
    - Storm Restoration that Exceeds the 10 Year Average
    - New OSHA 1910.269 Regulation Changes Involving the Protection of Workers from ARC Flash and General Requirement for Flame Retardant Clothing

LG&E KU
PPL companies

Plan Highlights

- Capital
  - *On target in 2014 to achieve 7&5 approved forecast.*
  - *Compounded Annual Growth Rate (CAGR) from 2014-2019 is 6.1%.*
  - *Continued focus on critical capital investments related to reliability and operational performance, replacement of aging infrastructure, storm and system repair, meeting customer demand and native load, and connecting new customers.*
  - *Major Initiatives:*
    - System Reliability Programs
    - System Enhancements to Improve Switching Capability at Critical Substations
    - LG&E Downtown Network Enhancements
    - Aging Infrastructure Replacement including the Pole Inspection & Treatment Program
    - Major Substation and Circuit Projects to Meet Demand
    - System Enhancements to Serve New Customers

PPL companies

Major Assumptions

- Customer expectations regarding levels of service and availability of information continue to increase.
- Reliability investments continue to target improvement in overall SAIDI/SAIFI metrics and specific circuits with customers experiencing multiple interruptions.
- New investments to further reinforce customer reliability include building in redundancy on select critical substations and purchase of an additional portable substation.
- Aging infrastructure investments include:
  - *Louisville Downtown Network accelerated PILC program and manhole lid replacement*
  - *Substation legacy equipment replacement*
  - *Replacement of LG&E substation underground exit cables*
  - *Rear easement hardening*
- Focus will continue to be placed on enhancing system reliability and making necessary repairs, meeting customer demand and native load, and replacing aging infrastructure.

PPL companies

Major Assumptions

- New Business:
  - *Moderate volume and inflationary increases are forecasted through the planning period.*
  - *Funding included for known major customer expansions/additions.*
- The Pole Inspection and Treatment Program will continue through the plan period.
- O&M storm budgets are based on 10 year average.
- Continue hazard tree removal program.
- Incremental headcount proposed to:
  - *Return some critical technical skills in –house and reduce the dependency on contractors*
  - *Address critical technical positions forecasted to be impacted by retirements.*

Financial Review – Prior Plan to Plan Expectation Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OPEX (O&M and BTL):					
Prior Plan Amount	**76,331**	**79,098**	**82,110**	**84,233**	**85,824**
Adjustments/Transfers:					
Safety & Tech Training - SERVCO	(1,267)	(1,301)	(1,348)	(1,391)	(1,433)
Safety & Tech Training - Distribution	(326)	(335)	(342)	(351)	(358)
Security - Transferred to CS	(3,148)	(3,235)	(3,300)	(3,374)	(3,442)
Transfer of Gas Line Clearance to GDO	(100)	(100)	(100)	(100)	(100)
BP Efficiency Savings	(992)	(1,348)	(894)	(977)	(977)
Current Plan Expectation	**70,498**	**72,779**	**76,126**	**78,040**	**79,514**

PPL companies

Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M:							
Labor	**23,793**	**25,171**	**24,558**	**24,956**	**25,703**	**26,519**	**27,314**
Non Labor							
Line Clearance [1]	22,359	22,796	23,032	24,142	24,880	26,872	26,995
Storm Restoration [2]	5,237	11,899	4,353	4,865	4,925	5,000	5,072
Outside Services	8,776	7,989	8,249	8,296	8,470	8,554	8,725
Materials	4,050	3,875	3,896	3,975	4,054	4,136	4,218
Transportation and Equipment	4,023	4,302	3,529	3,626	3,714	3,788	3,864
Other Non Labor	1,786	2,178	1,967	1,532	1,641	2,077	2,190
Total Non Labor	**46,231**	**53,039**	**45,026**	**46,436**	**47,684**	**50,427**	**51,064**
Subtotal O&M Expense [3]	**70,024**	**78,210**	**69,584**	**71,392**	**73,387**	**76,946**	**78,378**
Other Income/Expense*	**128**	**50**	**44**	**45**	**46**	**47**	**48**
*** (see OIE slide for detail)**							
Total OPEX	**70,152**	**78,260**	**69,628**	**71,437**	**73,433**	**76,993**	**78,426**

[1] Total Line Clearance including labor is $23.2M for 2013, $23.7M for 2014, $24M for 2015, $25.1M for 2016, $25.9M for 2017, $27.8M for 2018, and $28M for 2019.

[2] Total Storm Restoration including labor is $7.8M 2013, $16.4M for 2014, $7.3M for 2015 and $7.4M for 2016, $7.6M for 2017, $7.7M for 2018, and $7.9M for 2019.

[3] 2013 Actuals are not adjusted the Safety re-organization.

PPL companies

Financial Performance - OPEX

2013-2019 Other Income/Expenses (incl. BTL)
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OIE/BTL Expenses Only:							
Labor	-	-	-	-	-	-	-
Contributions	32	37	35	36	37	38	38
Employee Recognition	36	13	8	8	8	8	9
Meals and Meetings Exp.	24	-	-	-	-	-	-
Employee Moving Expense	21	-	-	-	-	-	-
Other	15	-	1	1	1	1	1
Total OIE / BTL Expense	**128**	**50**	**44**	**45**	**46**	**47**	**48**

2015-2019 O&M / Other Expense Reconciliation
($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Plan Expectation	**70,498**	**72,779**	**76,126**	**78,040**	**79,514**
Drivers:					
Pole Attachment Audit	91	95	103	98	106
Reduction in Tree Removal [1]	(1,300)	(1,300)	(2,627)	(1,300)	(1,300)
Storm Restoration	339	257	200	155	106
Budget Stretch	-	(394)	(369)	-	-
Current Plan	**69,628**	**71,437**	**73,433**	**76,993**	**78,426**

[1] This is a reduction compared to prior plan, but see pg. 14 Line Clearance for the year over year increases.

PPL companies

2013-2019 Capital Breakdown (w COR) – Accrual Basis ($000)

Project	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Electric Distribution							
New Business	55,176	54,989	59,334	65,358	65,875	68,151	71,512
Enhance the Network	31,439	27,092	35,460	31,662	39,603	40,248	46,360
Maintain the Network	46,822	48,596	54,157	55,061	59,665	58,813	60,582
Repair the Network	12,232	13,710	11,983	12,330	12,667	13,013	13,368
Miscellaneous	4,748	1,169	956	3,992	4,026	4,047	4,067
Total Capital and Cost of Removal	**150,417**	**145,556**	**161,890**	**168,403**	**181,836**	**184,272**	**195,889**

PPL companies

2015-2019
Capital Reconciliation (w COR) –Accrual Basis
($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Prior Plan	**162,943**	**164,452**	**180,513**	**192,929**	**N/A**
Changes:					
New Business - Major Projects	(382)	(3,428)	(925)		
New Business - Transformer Purchases	732				
New Business - All Other	(250)	75	112	117	
Network Initiatives - Incremental PILC	(2,000)	(2,060)	(2,122)	(2,175)	
Network Initiatives - KU SCADA Expansion	(500)	-	-	5,135	
Sys Enhancements - Enhancements to Meet Demand	613	2,204	1,662	5,702	
Transmission - Conductor Line Clearance and Relocation	(300)	(780)			
Purchase of Vehicles	3,000				
Transfer From Transmission - Distribution Capacitors	(278)	(278)	(278)	(278)	
Other	418	316	228	156	
Total Changes (Increases)/Decreases	**1,053**	**(3,951)**	**(1,323)**	**8,657**	**-**
Current Plan	**161,890**	**168,403**	**181,836**	**184,272**	**195,889**

PPL companies

Financial Performance

2013-2019 Headcount

Department	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
VP, Electric Distribution Operations	2	2	2	2	2	2	2
Transportation	3	3	3	3	3	3	3
System Restoration & LG&E Distribution	183	200	209	212	218	221	221
Electric Reliability	13	13	14	14	14	14	14
KU Distribution	296	299	300	299	299	299	299
Asset Management & Substations	157	163	167	172	173	172	172
Interns	6	5	7	7	7	7	7
TOTAL	**660**	**685**	**702**	**709**	**716**	**718**	**718**
From 2014 Business Plan		687	699	702			
Variance to 2014 Business Plan		-2	3	7			

Year to Year Increases (Decreases)	2014	2015	2016	2017	2018	2019
1.) Maintenance /Operational	26	15	7	7	2	
2.) Compliance – NERC, FERC, CIP, etc.						
3.) EPA/Environmental						
4.) Administrative/Corporate	-1	2				
TOTAL	**25**	**17**	**7**	**7**	**2**	**0**
Contractor Offsets By Year: (New hire reducing contractor use)	**0**	**11**	**8**	**6**	**3**	**0**

Operational Performance

Key Performance Indicators

KPI	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Safety - Employees Incident Rate	1.42	1.73	1.70	1.70	1.70	1.70	1.70
Safety - Contractors Incident Rate	1.11	2.00	1.85	1.85	1.85	1.85	1.85
SAIFI	0.84	0.86	1.00	0.99	0.98	0.97	0.96
SAIDI	81.61	82.96	95.00	94.00	93.00	92.00	91.00
Cash Cost Per Customer	229.15	269.35	275.48	283.45	297.06	300.52	312.80

PPL companies

Plan Risks

- Increased maintenance, inspection and operating costs associated with changing regulations
- Increased severe weather events
- Accelerating economy and customer growth
- Increased hazard trees and reliability impacts associated with the emerald ash borer
- Market driven cost increases in materials, supplies and services

Appendix

2013-2019
Year over Year Walk Forward
OPEX and Other Expense

2013 Actual	**70,152**
Labor Changes	1,378
Line Clearance	437
Storm Restoration	6,662
Non-Labor	(369)
2014 FC	**78,260**
Labor Changes	(613)
Line Clearance	236
Storm Restoration	(7,546)
Net Other Changes	(709)
2015 Budget	**69,628**
Labor Changes	398
Line Clearance	1,110
Storm Restoration	512
Budget Stretch	(394)
Net Other Changes	183
2016 Plan	**71,437**
Labor Changes	747
Line Clearance	738
Storm Restoration	60
Net Other Changes	451
2017 Plan	**73,433**

2017 Plan	**73,433**
Labor Changes	816
Line Clearance	1,992
Storm Restoration	75
Budget Stretch	369
Net Other Changes	308
2018 Plan	**76,993**
Labor Changes	795
Line Clearance	123
Storm Restoration	72
Net Other Changes	443
2019 Plan	**78,426**

(Decreases)/Increases

2014-2019
Headcount progression

(With Interns)

July 2014 Headcount	**677**
System Restoration & LG&E Distribution	6
KU Distribution	1
Asset Management & Substations	1
2014 Headcount FC	**685**
System Restoration & LG&E Distribution	9
Electric Reliability	1
KU Distribution	1
Asset Management & Substations	4
Interns	2
2015 Headcount Budget	**702**

2015 Headcount Budget	**702**
System Restoration & LG&E Distribution	3
KU Distribution	-1
Asset Management & Substations	5
2016 Headcount Plan	**709**
System Restoration & LG&E Distribution	6
Asset Management & Substations	1
2017 Headcount Plan	**716**
System Restoration & LG&E Distribution	3
Asset Management & Substations	-1
2018 Headcount Plan	**718**
2019 Headcount Plan	**718**

Increases / (Decreases)

PPL companies

Headcount & Employee Expense

2014-2019 Headcount

Business Unit Name	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Total Full Time & Part Time Headcount (without interns)	680	695	702	709	711	711

Employee Related Expenses ($000s)	2014	2015	2016	2017	2018	2019
1.) Training & Development	$108	$111	$130	$133	$135	$138
2.) Travel	$189	$214	$222	$226	$231	$236
3.) Meals and Expenses	$140	$101	$99	$102	$104	$106
4.) Employee Recognition	$13	$8	$9	$9	$9	$9
5.) Employee Dues and Memberships	$8	$6	$6	$7	$7	$7
TOTAL	**$458**	**$440**	**$466**	**$477**	**$486**	**$496**
Average Employee Expense per number of employees	**$ 674**	**$ 633**	**$ 664**	**$ 673**	**$ 684**	**$ 698**

PPL companies

2013-2019
Other Balance Sheet Costs
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Local Engineering							
Labor	12,889	13,602	15,722	15,843	16,080	16,562	17,059
Non labor	3,045	4,205	2,841	2,801	2,860	2,917	2,975
Total	**15,934**	**17,807**	**18,563**	**18,644**	**18,940**	**19,479**	**20,034**
Transportation	**20,979**	**22,308**	**22,236**	**22,812**	**23,256**	**23,721**	**24,196**
Total Other Costs	**36,913**	**40,115**	**40,799**	**41,456**	**42,196**	**43,200**	**44,230**

PPL companies

PPL companies

Gas Distribution

2015 Business Plan

September 17, 2014

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- Major Assumptions
- Financial Performance
  - o *Operating Expense*
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  - o *Headcount*
  - o *Key Performance Indicators*
- Plan Risks
- Appendix

PPL companies

Plan Highlights

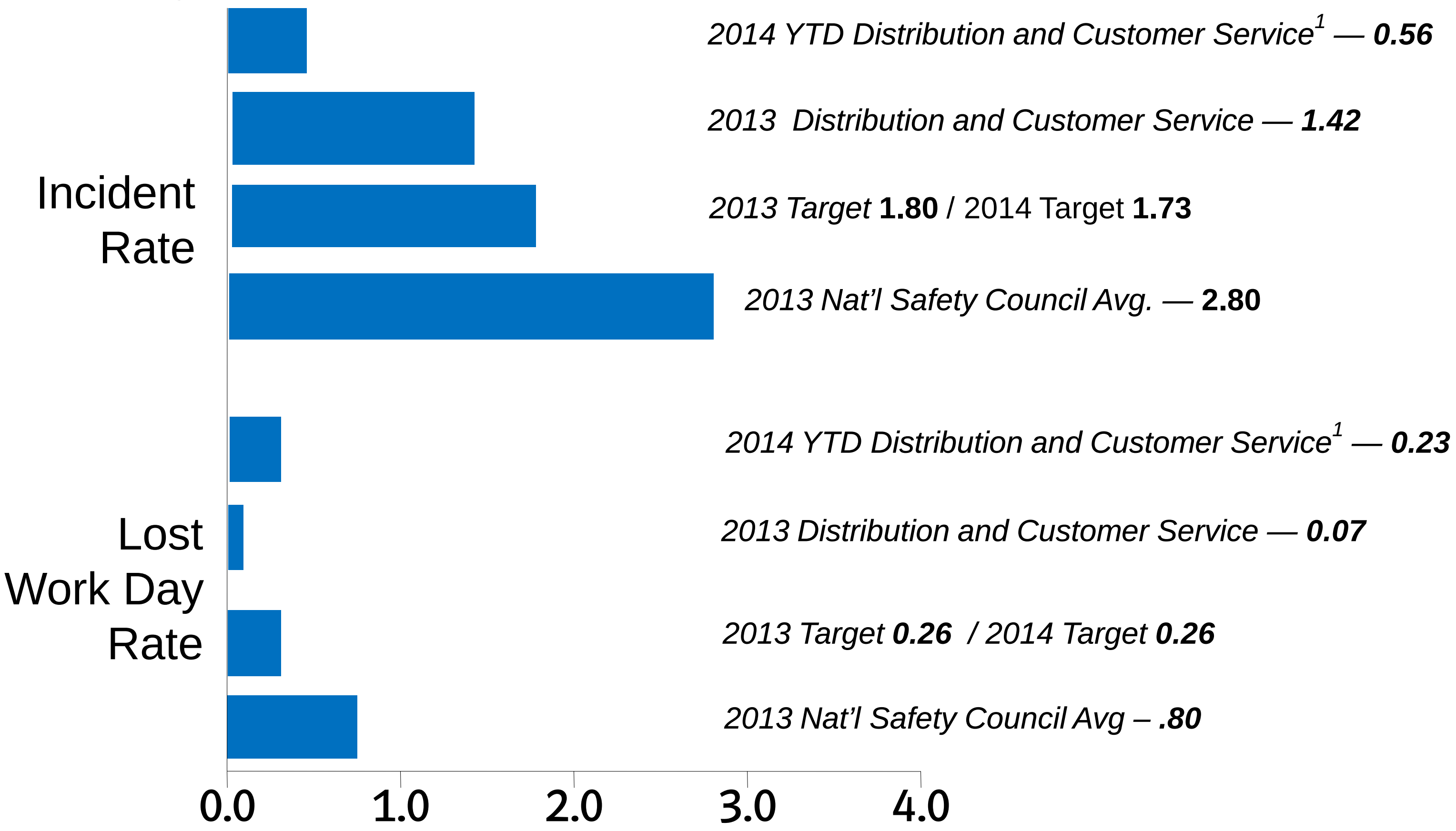
Customer satisfaction is a core value at LG&E and KU. Gas Distribution strives to provide safe, reliable, and low cost service to our customers, enhancing the quality of life in the areas we serve. We are committed to enhancing our relationship with our customers by delivering positive experiences that 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
  - Performance in customer facing areas
  - Gas system service reliability
  - Asset replacement to address aging infrastructure
  - System enhancement and regulator station work to help meet system capacity
  - Technology to enhance customer experience
  - Continued capital investments for gas riser and service line ownership

PPL companies

Plan Highlights

Safety Performance



[1] As of July YTD 2014

Plan Highlights

- Safety and Wellness
  - *Maintain industry leading performance*
  - *Enhance operational effectiveness within the COO organization*
  - *Distribution Integrity Management, Transmission Integrity Management, Public Awareness and Gas Control Room Management*
  - *Continue to improve employee, business partners, and public safety*
  - *Continue to improve motor vehicle safety*
  - *Identify, share and capitalize on industry best practices*
  - *Continue mock drills, leak detection training, and large scale outage restoration preparedness*
  - *Continuous improvements for gas emergency response*
  - *Promote wellness as an aspect of safety*

Plan Highlights

- Customer Experience
  - *Continue to be responsive to customer requests for new service or infrastructure relocations*
  - *Continue to promptly address issues raised and utilize internal resources to aid in response*
  - *Continue to identify and respond to opportunities to improve reliability performance*
  - *Invest in aging infrastructure replacement to continue long term service reliability*
  - *Continue focus on portraying a professional and positive customer image*
  - *Continue to respond to all outage events in an efficient and effective manner*
  - *Satisfy customer capacity needs*
  - *Continue to build on technology which enhances business processes, reduces cycle times, and enhances communications with customers*
  - *Continue communications process for major projects and large scale inspection activities*

PPL companies

Plan Highlights

- Reliability and Infrastructure
  - *Continue investments in gas system infrastructure to meet projected demand and regulatory requirements*
  - *Invest in gas infrastructure replacement to address the aging system and improve system performance and reliability*
  - *Invest in gas compression, gas processing equipment upgrades, pipeline replacements and gas storage wells to improve overall reliability, mitigate risk and maintain storage system deliverability*
  - *Manage gas transmission pipeline construction related to electric generation plants*

Plan Highlights

- OPEX
  - — *On target in 2014 to achieve 7&5 approved forecast.*
  - — *Compounded Annual Growth Rate (CAGR) from 2014-2019 is 2.8%.*
  - — *Major Initiatives:*
    - Regulatory Compliance
    - Implement key WFP additions
  - — *Major Financial Risks:*
    - Regulatory Uncertainty
- Cost of Sales
  - — *On target in 2014 to achieve 7&5 approved forecast.*
  - — *Compounded Annual Growth Rate (CAGR) from 2014-2019 is 1.5% without maximum allowable operating pressures (MAOPs) testing.*
  - — *Major Initiatives:*
    - Gas Main & Riser Replacement Programs
    - Pressure Testing for MAOPs (ranges between $5M and $16.5M in 2016-2019)
  - — *Major Financial Risks:*
    - MAOP

PPL companies

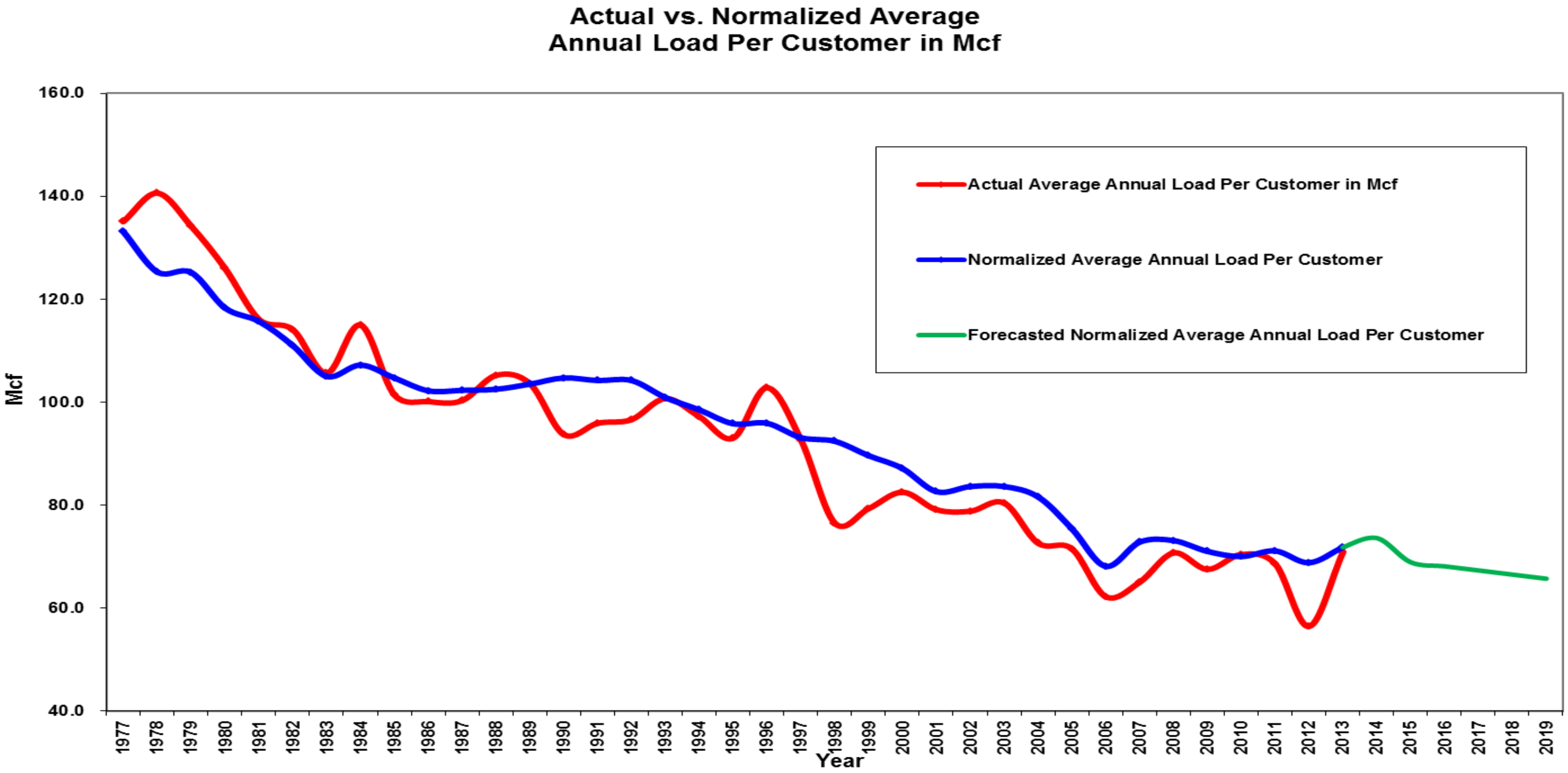
Plan Highlights

- Capital
  - *On target in 2014 to achieve 7&5 approved forecast.*
  - *Compounded Annual Growth Rate (CAGR) from 2014-2019 is a decrease of 10.5% in total or positive 1.8% without Gas Tracker capital.*
  - *Major Capital Initiatives:*
    - Reliability / Asset Replacement
    - Gas Leak Mitigation
    - Customer Gas Service Ownership and Service Riser Replacement Programs
    - Gas Compressor Station and System Enhancements
    - Gas Transmission/Distribution Integrity Management Programs

PPL companies

Plan Highlights

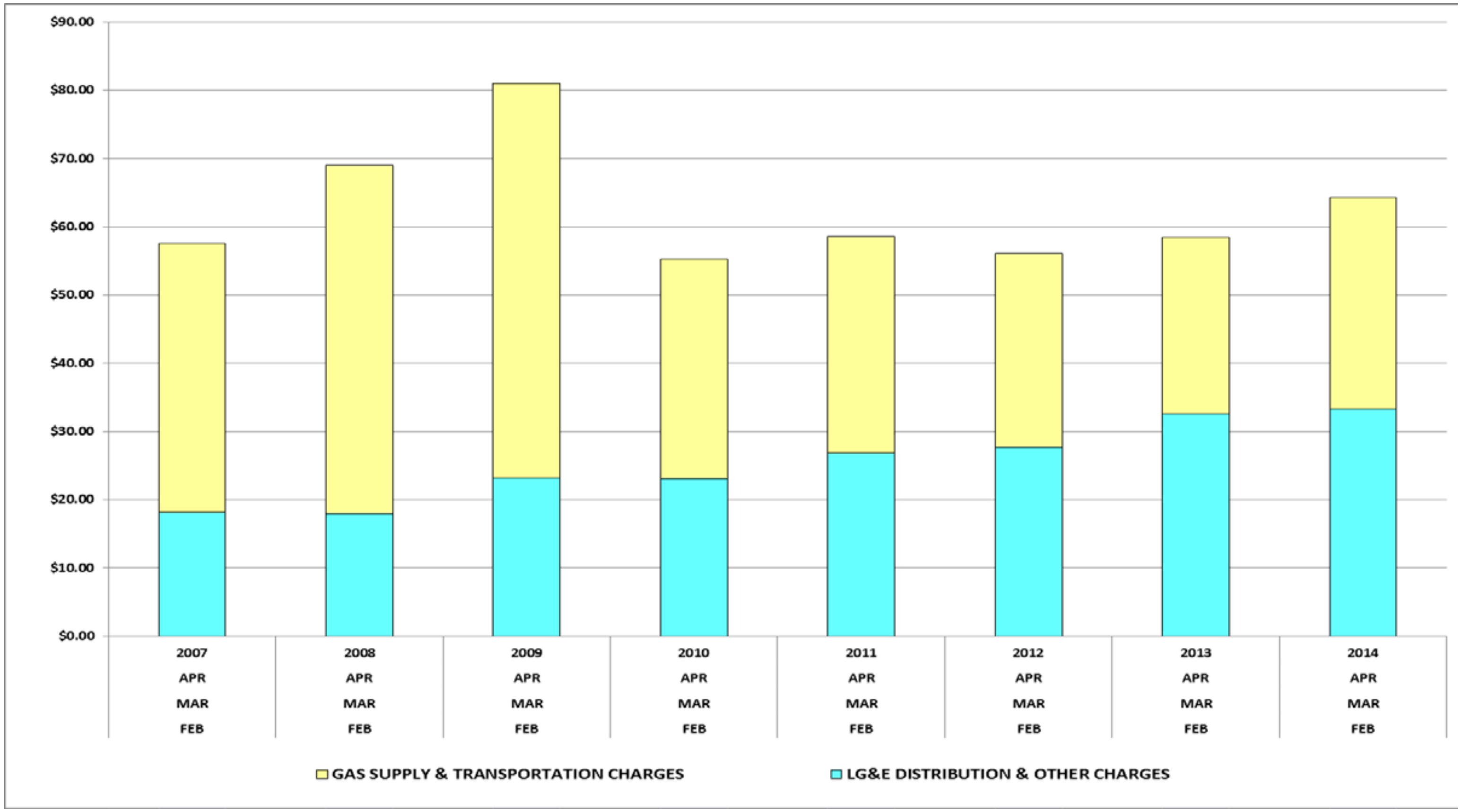
Residential Gas Use per Customer



LG&E KU
PPL companies

Plan Highlights

Typical Monthly Residential Gas Bill by Component (6 Mcf/month)



PPL companies

Plan Highlights

Gas Delivered by Class in Bcf

Class	2014	2015	2016	2017	2018	2019
Residential	*21.649*	*20.266*	*20.078*	*19.880*	*19.678*	*19.487*
Commercial	*11.172*	*10.570*	*10.533*	*10.468*	*10.404*	*10.368*
Industrial	*2.201*	*2.371*	*2.515*	*2.640*	*2.751*	*2.848*
Transportation	*11.725*	*12.003*	*12.099*	*12.104*	*12.040*	*12.067*
Total	*46.747*	*45.210*	*45.225*	*45.092*	*44.873*	*44.770*

Major Assumptions

- Customer expectations regarding levels of service and availability of information will continue to increase.
- Incremental headcount is needed to meet increased regulatory and compliance demands, transfer critical knowledge in preparation for retirements, and offset of contractors.
- New Business assumes moderate customer growth and inflationary increases through the planning period.
- Continuation of the Gas Line Tracker mechanism, KPSC approved in 2012.
- Gas Supply Clause remains fundamentally unchanged.
- Continued focus on reliability initiatives.

Major Assumptions

- New gas safety regulatory requirements will likely:
  - *Require operators to validate MAOPs of gas transmission pipelines. Pre-1970 and Post-1970 costs are modeled as Gas Tracker cost of sales.*
  - *Expand pipeline integrity requirements beyond high consequence areas.*
  - *Expand operator qualification requirements to construction activities.*
  - *Nominal capital is included to address MAOP validation of gas transmission pipelines.*
- Based upon 2013/2014 Winter operating experience:
  - *Forecasted Design Day for 2015 has increased to 665,000 Mcf/day from 629,000 Mcf/day estimated in the prior BP. During the current 5-year planning period, the forecasted Design Day gradually decreases to 656,000 Mcf/day.*
  - *Gas storage operating risk is addressed through staffing and project funding.*
  - *Main replacement and gas riser projects will address infrastructure vulnerable to cold weather issues.*

PPL companies

Financial Review – Prior Plan to Plan Expectation Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OPEX (O&M and BTL):					
Prior Plan Amount	**33,811**	**33,209**	**34,513**	**36,733**	**36,213**
Adjustments/Transfers:					
Transfer of Gas Line Clearance from EDO	100	100	100	100	100
BP Efficiency Savings	(792)	(1,212)	(1,237)	(1,366)	(1,366)
Current Plan Expectation	**33,119**	**32,097**	**33,376**	**35,467**	**34,947**

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
GMEXP (OCOS):					
Prior Plan Amount	**4,009**	**3,875**	**3,729**	**3,817**	**4,093**
Adjustments/Transfers:					
None					
Current Plan Expectation	**4,009**	**3,875**	**3,729**	**3,817**	**4,093**

Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M:							
Labor	**14,119**	**15,747**	**17,192**	**17,931**	**18,178**	**18,723**	**19,285**
Non Labor							
Inline Inspections	203	438	1,088	809	760	1,106	1,045
Outside Services	7,960	8,525	8,736	8,315	9,023	9,442	9,823
Materials	3,209	2,812	3,243	2,884	2,949	3,007	3,068
Transportation and Equipment	1,958	2,212	1,393	1,416	1,444	1,473	1,502
Other Non Labor	2,340	2,106	1,808	1,644	1,676	1,711	1,745
Total Non Labor	**15,670**	**16,093**	**16,268**	**15,068**	**15,852**	**16,739**	**17,183**
Subtotal O&M Expense	**29,789**	**31,840**	**33,460**	**32,999**	**34,030**	**35,462**	**36,468**
Other Income/Expense* * (see OIE slide for detail)	**51**	**15**	**15**	**15**	**15**	**16**	**16**
Total OPEX	**29,840**	**31,855**	**33,475**	**33,014**	**34,045**	**35,478**	**36,484**

PPL companies

Financial Performance - OPEX

2013-2019 Other Income/Expenses (incl. BTL)
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OIE/BTL Expenses Only:							
Labor	-	-	-	-	-	-	-
Contributions	11	-	-	-	-	-	-
Employee Recognition	5	15	15	15	15	16	16
Meals and Meetings Exp.	6	-	-	-	-	-	-
Other	29	-	-	-	-	-	-
Total OIE / BTL Expense	**51**	**15**	**15**	**15**	**15**	**16**	**16**

PPL companies

2015-2019 O&M / Other Expense Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Plan Expectation	**33,119**	**32,097**	**33,376**	**35,467**	**34,947**
Drivers:					
Inline Inspections - Regulatory	728	(580)	(239)	399	(802)
WFP	(345)	(412)	(524)	(497)	(477)
Franchise Fees	587	599	611	623	635
All Other	(1,326)	(524)	(517)	(536)	(893)
Total Drivers (Increases)/Decreases	**(356)**	**(917)**	**(669)**	**(11)**	**(1,537)**
Current Plan	**33,475**	**33,014**	**34,045**	**35,478**	**36,484**

PPL companies

Financial Performance

2013-2019 Margin Expenses / Cost of Sales
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Margin Expenses							
Mechanism Recoverable:							
Gas Tracker	970	1,349	1,406	6,361	16,398	17,935	11,475
Gas Losses	1,793	2,198	2,304	2,212	2,256	2,302	2,347
Total	**2,763**	**3,547**	**3,710**	**8,573**	**18,654**	**20,237**	**13,822**

PPL companies

2015-2019 Margin/Cost of Sales Reconciliation
($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Mechanism Recoverable					
Prior Plan / Plan Expectation	**4,009**	**3,875**	**3,729**	**3,817**	**4,093**
Drivers					
Gas Losses - Lower Rate	32	174	177	181	314
MAOP - Pressure Testing	-	(5,000)	(15,000)	(16,500)	(10,000)
Gas Tracker - Revised Estimates	267	128	(102)	(101)	(43)
Total Drivers (Increases)/Decreases	**299**	**(4,698)**	**(14,925)**	**(16,420)**	**(9,729)**
Current Plan	**3,710**	**8,573**	**18,654**	**20,237**	**13,822**

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PPL companies

2013-2019 Capital Breakdown (w COR) – Accrual Basis ($000)

Project	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Gas Distribution							
New Business	6,001	7,845	6,029	6,207	6,526	6,424	6,694
Enhance the Network	24,429	24,406	26,228	28,059	12,391	7,456	7,522
Maintain the Network	39,341	45,008	49,943	48,662	46,126	23,960	29,309
Repair the Network	314	253	279	287	297	305	313
Miscellaneous	1,119	379	608	387	836	859	882
Total Capital (w COR)	**71,204**	**77,891**	**83,087**	**83,602**	**66,176**	**39,003**	**44,721**
Gas Tracker	**45,121**	**50,888**	**53,901**	**58,223**	**38,961**	**14,849**	**15,146**
Total Capital (Excl. Gas Tracker)	**26,083**	**27,003**	**29,186**	**25,379**	**27,215**	**24,154**	**29,575**

LG&E KU
PPL companies

2015-2019
Capital Reconciliation (w COR) –Accrual Basis
($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Prior Plan	**87,010**	**85,382**	**63,165**	**32,316**	**N/A**
Changes:					
Tracker - Gas Service Riser Replacement and Ownership	3,500	2,000	7,000		
Tracker - Gas Main Replacements (Large Scale and Priority)			(5,000)		
Tracker - Beltline Priority Project			(5,000)	(5,000)	
Tracker - Other Projects	407	(220)	(11)	373	
Gas System Reinforcement and Uprate Projects	(660)	(400)			
GC&S - Mt. Washington/Lebanon Jct. Transm. Pipeline	-	-	-	(4,000)	
GC&S - East End Gas Transm. System Reinforcement	1,330	2,850	3,600	-	
GC&S - Well Drilling in Magnolia and Muldraugh	(460)	725			
GC&S - Various Gas Control and Compressor Station Projects	171	(2,966)	(3,186)	2,371	
Tools and Equipment	(428)	(231)	(524)	(541)	
Non-Tracker - Other Projects	63	22	110	110	
Total Changes (Increases)/Decreases	**3,923**	**1,780**	**(3,011)**	**(6,687)**	**-**
Current Plan	**83,087**	**83,602**	**66,176**	**39,003**	**44,721**

LG&E KU
PPL companies

Financial Performance

2013-2019 Headcount

Department	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
VP, Gas Distribution Operations	2	2	2	2	2	2	2
Gas Regulatory	26	28	36	36	37	37	37
Gas Management & Supply	5	5	6	6	6	6	6
Gas Operations, Construction & Engineering	104	108	110	112	112	111	111
Gas Control & Storage	91	102	102	104	107	105	102
Interns	1	4	4	4	4	4	4
TOTAL	**229**	**249**	**260**	**264**	**268**	**265**	**262**
From 2014 Business Plan		247	243	246			
Variance to 2014 Business Plan		2	17	18			

Year to Year Increases (Decreases)	2014	2015	2016	2017	2018	2019
1.) Maintenance / Operational	20	3	4	3	-3	-3
2.) Compliance – NERC, FERC, CIP, etc.		8		1		0
3.) EPA / Environmental						
4.) Administrative / Corporate						
TOTAL	**20**	**11**	**4**	**4**	**-3**	**-3**
Contractor Offsets By Year: (New hire reducing contractor use)	**0**	**7**	**0**	**0**	**0**	**0**

Operational Performance

Key Performance Indicators

KPI	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Safety - Employees Incident Rate	1.42	1.73	1.70	1.70	1.70	1.70	1.70
Safety - Contractors Incident Rate	1.11	2.00	1.85	1.85	1.85	1.85	1.85
Gas Response Priority 1 Calls (minutes)	41.8	42.0	42.0	42.0	42.0	42.0	42.0

PPL companies

Plan Risks

- Increased Capital and O&M Costs due to Industry Regulatory Actions
- Additional Mitigation from Gas Transmission Line Inspections
- Economic Development and the Pace of the Economic Recovery
- Impact Associated with Possible Early Retirements
- Material and Equipment Price Increases
- Fuel Prices

Appendix

PPL companies

2013-2019
Year over Year Walk Forward
OPEX and Other Expense

2013 Actual	**29,840**
Labor Changes	1,628
Pipeline InLine Inspections	235
Other Non-Labor	152
2014 FC	**31,855**
Labor Changes	1,445
Pipeline InLine Inspections	650
Shift in GC&S NL Expenses (2016 to 2015)	360
Gas Franchise Fees	(573)
Gas Dist - Managing Leak Backlog	(100)
Net Other Changes	(162)
2015 Budget	**33,475**
Labor Changes	739
Pipeline InLine Inspections	(279)
Shift in GC&S NL Expenses (2016 to 2015)	(360)
Gas Dist - Managing Leak Backlog	(84)
Well Bore Inspections (15 to 20 yr. cycle)	(100)
Net Other Changes	(377)
2016 Plan	**33,014**

2016 Plan	**33,014**
Labor Changes	247
Pipeline InLine Inspections	(49)
Restoration of GC&S NL Expenses (Shift from 2016 to 2015)	360
Net Other Changes (NL Escalation)	473
2017 Plan	**34,045**
Labor Changes	545
Pipeline InLine Inspections	346
Net Other Changes (NL Escalation)	542
2018 Plan	**35,478**
Labor Changes	562
Pipeline InLine Inspections	(61)
Net Other Changes (NL Escalation)	505
2019 Plan	**36,484**

(Decreases)/Increases

PPL companies

2013-2019
Year over Year Walk Forward
GMEXP / Cost of Sales

2013 Actual	**2,763**
Gas Tracker	379
Fuel Gas	405
2014 FC	**3,547**
Gas Tracker	57
Fuel Gas	106
2015 Budget	**3,710**
Gas Tracker	(45)
Gas Tracker - MAOP - Pressure Testing	5,000
Fuel Gas	(92)
2016 Plan	**8,573**
Gas Tracker	37
Gas Tracker - MAOP - Pressure Testing	10,000
Fuel Gas	44
2017 Plan	**18,654**
Gas Tracker	37
Gas Tracker - MAOP - Pressure Testing	1,500
Fuel Gas	46
2018 Plan	**20,237**
Gas Tracker	40
Gas Tracker - MAOP - Pressure Testing	(6,500)
Fuel Gas	45
2019 Plan	**13,822**

(Decreases)/Increases

2014-2019
Headcount Progression

(With Interns)

July 2014 Headcount	**243**
Gas Control & Storage	6
2014 Headcount FC	**249**
Gas Regulatory	8
Gas Management & Supply	1
Gas Operations, Construction & Engineering	2
2015 Headcount Budget	**260**
Gas Operations, Construction & Engineering	2
Gas Control & Storage	2
2016 Headcount Plan	**264**

2016 Headcount Plan	**264**
Gas Regulatory	1
Gas Control & Storage	3
2017 Headcount Plan	**268**
Gas Operations, Construction & Engineering	-1
Gas Control & Storage	-2
2018 Headcount Plan	**265**
Gas Control & Storage	-3
2019 Headcount Plan	**262**

Increases / (Decreases)

PPL companies

Headcount & Employee Expense

2014-2019 Headcount

Business Unit Name	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Total Full Time & Part Time Headcount (without interns)	245	256	260	264	261	258

Employee Related Expenses ($000s)	2014	2015	2016	2017	2018	2019
1.) Training & Development	$160	$185	$185	$189	$193	$197
2.) Travel	$69	$85	$85	$86	$88	$89
3.) Meals and Expenses	$18	$26	$26	$27	$27	$28
4.) Employee Recognition	$15	$15	$15	$15	$16	$16
5.) Employee Dues and Memberships	$0	$0	$0	$0	$0	$0
TOTAL	**$262**	**$311**	**$311**	**$317**	**$324**	**$330**
Average Employee Expense per number of employees	**$ 1,069**	**$ 1,215**	**$ 1,196**	**$ 1,201**	**$ 1,241**	**$ 1,279**

PPL companies

2013-2019
Other Balance Sheet Costs
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Local Engineering							
Labor	2,115	1,617	2,494	2,627	2,641	2,721	2,802
Non labor	212	372	401	402	412	421	429
Total	**2,327**	**1,989**	**2,895**	**3,029**	**3,053**	**3,142**	**3,231**

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Transmission

2015 Business Plan

September 17, 2014

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Plan Highlights

- *The 2015-2019 Transmission Business Plan will continue a culture of strong safety performance and regulatory compliance, maintain position as a low cost provider and improve system reliability and performance.*
- *Focus on reliability performance improvement through analysis and capital improvements to reduce customer exposure and reduce outages.*
  - *Outage analysis and cause determination*
  - *Installation of sectionalizing circuit breakers and switches to reduce line exposure*
  - *Assess and improve line sections based on performance*
  - *Targeted replacement of assets including wood poles, insulators, static lines, relays, control houses, circuit breakers based on age, condition and performance criteria*
- *Continue to improve balance between contractors and employees focusing on core skillsets*
- *Transmission line and substation projects driven by generation expansion plans, interconnection agreements and through the ITO approved Transmission Expansion Plan process driven by NERC planning standards and LKE system planning guidelines to reliably serve firm load*
- *Compliance initiatives including ongoing facility rating verification and CIP v5 implementation*
- *Transmission line extensions to serve new native distribution substations in EDO business plan*
- *Emergency maintenance and asset replacement due to in service failure based on historical trends*

Major Assumptions

Reliability and Asset Management:

- *The strategy to improve reliability is based on historical performance and addressing line segments on a prioritized basis:*
  - *Segmenting circuits to reduce customer exposure from sustained outages.*
  - *Rebuilding/restoring line segments based on performance for both sustained and momentary outages.*
- *Targeted asset replacement based on risk criteria will maintain system performance over time:*
  - *Control house and protection and control replacements based on performance and age.*
  - *Circuit breaker replacements based on age/condition/maintainability.*
  - *Static wire replacements based on age and lightning performance.*
  - *Structure replacements based on condition.*
    - *Wood poles inspected every 6 years.*
    - *Steel structures every 12 years.*
- *Storm damage costs are based on a 5 year average. It is assumed there will be one transformer failure per year at a cost of $1.5m.*
- *O&M expenses for maintenance costs will be consistent with historical trends.*

Major Assumptions

Expansion Plan and Native Load:

- *Projects in the Business Plan are based on the 2014 annual Transmission Expansion Plan (TEP). It is assumed that the ITO will approve the TEP without significant revisions.*
- *The TEP includes funding for rating increases to certain transmission lines based on high level estimates. Detailed costs will be developed after surveying and subsequent analyses are completed.*
- *The plan assumes there will be no funding needed to accommodate new long term, firm service requests.*
  - *There are no funds in the plan for future project work that may result from transmission requests from the municipal customers who recently terminated their wholesale agreements.*
  - *Recent transmission requests for the E.W. Brown solar facility and a Bluegrass combustion turbine are not expected to require significant project work prior to approval.*
- *The Plan does not include new projects to mitigate potential reliability constraints in Western Kentucky.*
  - *Given announcements from neighboring utilities, additional studies are underway to determine if reliability constraints will occur for various external scenarios with Green River 3 & 4 retired.*
  - *If constraints and mitigating projects are recommended, extension of the operations of Green River units 3 & 4 may be required to allow time to implement.*
- *A new combined cycle gas turbine (807MW summer/898MW winter) will be in-service at Green River by May 1, 2021. Construction will start in 2018 and it is estimated that $58m is needed during the plan period and a total of $78m needed through 2021 to construct necessary transmission improvements.*
- *Connection costs for native load are coordinated with Distribution planning requirements and are estimated at $20m over the 5 year plan.*

Major Assumptions

Regulatory and Compliance:

- *FERC issued a NOPR proposing to skip CIP V4 and implement CIP V5 on an accelerated schedule. It is assumed that the implementation timeframe will require compliance by April 2016.*
  - *The plan assumes CIP V5 will change electronic logging of access requirements which will require installation of equipment for medium impact cyber systems. It is assumed that low impact systems will not require material expenditures to address.*
  - *Additional CIP versions beyond 5 will occur outside this 5 year plan.*

[redacted]

- *Expected revisions to other NERC Reliability standards will not result in material incremental expenditures.*
- *Bulk Electric System Line Ratings:*
  - *All lines 100kV and above will be surveyed every 5 years to confirm line ratings. Ongoing surveying and analysis of the lines is projected to cost $300k in 2015 and 2016 and cost $700k annually thereafter.*
  - *Ongoing surveys will not result in material expenditures.*
- *It is assumed FERC will approve compliance filings related to Order 1000 and resulting processes, once implemented, will not result in material capital or O&M expenditures.*

PPL companies

Major Assumptions

Operational and other:

- *Transerv will be retained as the ITO service provider to LGE/KU at escalated costs based on the existing contract*
- *TVA will be retained as the Reliability Coordinator (RC) with a new five year contract beginning September 1, 2014. The plan is funded to match the costs of the new agreement.*
- *Gross margin expenses related to the MISO Exit Agreement (de-pancaking) will continue and increase in 2019.*
- *Annual internal labor escalation rates: 3.0%*
- *Capital project contingency is 5-10%*

Financial Review – Prior Plan to Expectation Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OPEX (O&M and BTL):					
Prior Plan Amount	31,097	32,923	34,900	36,482	37,338
Adjustments/Transfers:					
Safety Reorganization	(102)	(106)	(108)	(111)	(114)
Control Center Guards	120	122	125	127	130
Pole Inspections	(700)	(714)	(728)	(743)	(433)
Bulk Electric System LiDAR	-	(500)	(510)	(520)	(530)
Back Up Control Center Delay	-	-	(201)	(406)	(414)
EPRI - Lines	(75)	(77)	(78)	(80)	(81)
O/S for GeoMagDist, HumanPer	(256)	(262)	(134)	(158)	(140)
Moving Expense	100	102	104	106	108
Mock Audit Preparation	(102)	50	105	-	-
Substation SPCC Review	45	31			
Storms Updated 5 Year Average	84	86	88	89	92
Other Adjustments	(103)	125	(39)	1	201
Current Expectation	30,108	31,780	33,524	34,787	36,157

	2015 Budget	2016 Plan	2017 Plan	2018 Plan
GMEXP (OCOS):				
Prior Plan Amount	12,081	12,730	13,360	14,247
Adjustments/Transfers:				
	-	-	-	-
Current Expectation	12,081	12,730	13,360	14,247

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PPL companies

Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M Expenses Only:							
Labor	11,977	11,832	12,342	12,737	13,106	13,783	14,209
Line Clearing (nonlabor)	6,123	6,836	6,261	6,719	7,723	8,288	8,651
Pole Inspections (nonlabor)	563	290	600	612	624	637	974
Storms (nonlabor)	385	674	380	388	396	403	412
Bulk Electric System LiDAR	240	250	255	700	714	728	743
Other Non-Labor	10,025	9,458	9,160	9,422	9,763	9,831	10,048
Subtotal O&M Expense	29,313	29,340	28,998	30,578	32,326	33,670	35,037
Other Income/Expense*	271	10	110	112	115	117	119
* (see OIE slide for detail)							
Total OPEX	29,584	29,350	29,108	30,690	32,441	33,787	35,157

PPL companies

Financial Performance - OPEX

2013-2019 Other Income/Expenses (incl. BTL)
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OIE/BTL Expenses Only:							
Labor	-	-	-	-	-	-	-
Contributions	47	-	-	-	-	-	-
Employee Recognition	-	-	6	6	6	6	6
Meals and Meetings Exp.	8	10	10	10	11	11	11
Penalties	139	-	-	-	-	-	-
Moving Expenses & Other	77	-	94	96	98	100	102
Total OIE / BTL Expense	271	10	110	112	115	117	119

PPL companies

2015-2019 O&M / Other Expense Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Expectation	30,108	31,780	33,524	34,787	36,157
Drivers:					
Delay EMS pre-hire & retirement	(105)	(105)	(105)	105	105
Interns	(120)	(124)	(127)	(131)	(135)
Substation Maintenance	(100)	(100)	(100)	(100)	(100)
Final Capital Impact on Labor	(109)	124	(70)	(385)	(6)
Line Clearing 69kV	(416)	(594)	(240)	(328)	(637)
Other non-labor	(150)	(291)	(441)	(161)	(227)
Current Plan	29,108	30,690	32,441	33,787	35,157

PPL companies

Financial Performance

2013-2019 Margin Expenses / Cost of Sales
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Margin Expenses							
Mechanism Recoverable:							
Total	-	-	-	-	-	-	-
All other Cost of Sales:							
TVA - RC	1,997	2,034	2,391	2,439	2,487	2,537	2,588
Transerv - ITO	2,588	2,620	2,580	2,644	2,710	2,778	2,847
Misc Transmission Expenses	6,485	7,387	6,966	6,889	7,351	7,716	11,025
Total	11,070	12,040	11,936	11,972	12,549	13,031	16,461
Total Margin/Cost of Sales	11,070	12,040	11,936	11,972	12,549	13,031	16,461

PPL companies

2015-2019 Margin/Cost of Sales Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Mechanism recoverable					
Expectation					
Drivers:					
Current Plan	-	-	-	-	-
Other					
Expectation	12,081	12,730	13,360	14,247	N/A
Drivers					
TVA - RC	200	170	141	108	
Transerv - ITO	(497)	(586)	(628)	(894)	
Miscellaneous Transmission Exp	152	(342)	(324)	(430)	
Current Plan	11,936	11,972	12,549	13,031	16,461

PPL companies

2013-2019 Capital Breakdown (w COR) – Accrual Basis ($000)

Project	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Generation Expansion Plan (GEP)							
Green River	-	35	-	-	-	24,756	33,329
Cane Run CCGT - Transmission	15,276	6,423	2,159	1,200	-	-	-
3rd Combined Cycle (2025)	-	-	-	-	-	-	-
Ongoing Capital							
TEP	11,433	7,370	11,931	500	26,666	22,800	17,576
Reliability	-	-	3,590	4,228	8,854	958	1,775
Customer Requests	3,228	3,837	1,491	102	1,024	101	-
Emergency Replacements	2,408	5,976	6,440	6,215	6,221	6,222	6,495
Native Load	996	79	1,122	2,156	3,975	6,308	8,411
Proactive Replacements	37,302	21,929	31,173	39,114	35,844	34,939	52,741
Special Projects							
Louisville Upgrades	10,462	20,478	2,683	-	-	-	-
Line Clearance NERC Alert	12,558	15,673	-	-	-	-	-
Line Clearance	889	33	-	-	-	-	-
Cyber Security (CIP)	759	771	688	1,191	1,191	1,191	1,003
Other	162	270					
Total Capital and Cost of Removal	95,473	82,875	61,275	54,705	83,776	97,276	121,330

2015-2019
Capital Reconciliation (w COR) –Accrual Basis
($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Prior Plan	64,178	93,146	127,232	72,884	N/A
Changes:					
Generation Expansion Plan (GEP)					
Green River	(10,000)	(20,000)	(40,000)	14,756	
Cane Run CCGT - Transmission	(3,827)	1,200	-	(4,369)	
Ongoing Capital					
TEP	(2,893)	(12,699)	9,819	9,862	
Reliability	3,590	3,146	1,145	958	
Customer Requests	(438)	(183)	739	(168)	
Emergency Replacements	1,851	1,627	1,633	1,633	
Native Load	(964)	(1,358)	(3,997)	941	
Proactive Replacements	7,570	5,486	(9,701)	774	
Special Projects					
Louisville Upgrades	2,683	-	-	-	
Line Clearance	-	(8,173)	-	-	
Back-up Control Center	-	(7,514)	(3,122)	-	
Cyber Security (CIP)	(452)	50	52	51	
Other	(23)	(23)	(23)	(46)	
Current Plan	61,275	54,705	83,776	97,276	121,330

PPL companies

Financial Performance

2013-2019 Headcount

Department	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Sr. Managers	**6**	**5**	**5**	**5**	**5**	**5**	**5**
Lines	**30**	**30**	**32**	**33**	**34**	**34**	**34**
Protection & Controls	**18**	**23**	**24**	**24**	**24**	**24**	**25**
Substation Construction	**15**	**16**	**19**	**20**	**22**	**22**	**23**
System Operations	**39**	**41**	**41**	**41**	**41**	**41**	**41**
EMS	**8**	**9**	**9**	**9**	**9**	**11**	**10**
Strategy & Planning	**13**	**14**	**15**	**15**	**15**	**15**	**15**
Reliability & Perf Stds.	**4**	**4**	**4**	**4**	**4**	**5**	**5**
Policy & Tariffs	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Reliability & Compliance	**4**	**3**	**3**	**3**	**3**	**3**	**3**
Interns	**4**	**8**	**8**	**8**	**8**	**8**	**8**
TOTAL	**144**	**156**	**163**	**165**	**168**	**171**	**172**
From 2014 Business Plan		157	162	164			
Variance to 2014 Business Plan		-1	1	1			

Year to Year Increases (Decreases)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
1.) Maintenance /Operational	11	7	2	3	3	1
2.) Compliance – NERC, FERC, CIP, etc.	1					
3.) EPA/Environmental						
4.) Administrative/Corporate						
TOTAL	**12**	**7**	**2**	**3**	**3**	**1**
Contractor Offsets By Year: (New hire reducing contractor use)	**1**	**5**	**2**	**2**		

Note: The 2013 Year End figure and the 2014 Business Plan figures exclude the Safety Position that was moved from Transmission.

PPL companies

Operational Performance

Key Performance Indicators

KPI	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Recordable Injury Incident Rate - Employees	0.00	0.00	1.70	1.70	1.70	1.70	1.70
Recordable Injury Incident Rate - Contractors	2.18	1.42	1.85	1.85	1.85	1.85	1.85
SAIDI (minutes)	13.5	11.7	11.6	11.6	11.6	10.6	10.6

Notes:

The forecasted Recordable Injury Incident Rate is calculated using the actual number of injuries through September 9, 2014 and the actual hours worked (year-to-date average hours per month assumed for 12 months).

The forecasted SAIDI is based on actual through July and budget for August through December.

PPL companies

Plan Risks

- *Estimated costs for regulatory and compliance requirements could be materially higher.*
  - *Final CIP-14 assessments for substation physical security may result in substations coming into scope.*
  - *Requirements for low and medium rated assets under CIP V5 may be significantly greater than anticipated.*
- *Final transmission expansion plan costs may be materially different from the 2015 Business Plan.*
- *Actual costs for work related to equipment failures and storm restoration may exceed projections.*
- *Future third party requests for long term, firm transmission service may result in the need for significant additional infrastructure upgrades.*

Appendix

2013-2019
Year over Year Walk Forward
OPEX and Other Expense

	$000s
2013 Actual	29,584
EMS and Safety Coordinator Labor moved out of Transmission	(498)
Other Labor Change	320
Non-labor Change	(56)
2014 FC	29,350
Labor Change	532
Line Clearing	157
Inpections	(185)
Storms	(350)
Substations Nonlabor	(434)
Transmission Control Center Guards	120
Other	(82)
2015 Budget	29,108
Labor Change	156
Line Clearing	778
LiDAR	445
Other	203
2016 Plan	30,690
Labor Change	566
Line Clearing	803
Other	382
2017 Plan	32,441
Labor Change	984
Line Clearing	175
Other	187
2018 Plan	33,787
Labor Change	105
Line Clearing	743
Inspections	338
Other	184
2019 Plan	35,157

PPL companies

2013-2019
Year over Year Walk Forward
GMEXP / Cost of Sales

	$000s
2013 Actual	**11,070**
Tranvserv	32
TVA	37
Misc Transmission Expense	901
2014 FC	**12,040**
Tranvserv	(40)
TVA	357
Misc Transmission Expense	(421)
2015 Budget	**11,936**
Tranvserv	65
TVA	48
Misc Transmission Expense	(77)
2016 Plan	**11,972**
Tranvserv	66
TVA	49
Misc Transmission Expense	462
2017 Plan	**12,549**
Tranvserv	68
TVA	50
Misc Transmission Expense	364
2018 Plan	**13,031**
Tranvserv	69
TVA	51
Misc Transmission Expense	3,310
2019 Plan	**16,461**

PPL companies

2014-2019
Headcount progression

2014 Headcount (As of July 2014)	152
Backfills	3
Interns	1
2014 Headcount FC - Year End	156
Asset Management	1
Planning Engineer - Pull Forward	1
Inspectors - Replacing Contractors	2
Drafters - Replacing Contractors	2
Relay Technician	1
2015 Headcount Budget	163
Inspector - Replacing Contractors	1
Drafter - Replacing Contractors	1
2016 Headcount Plan	165
Inspectors - Replacing Contractors	2
Capital Project Coordinator	1
2017 Headcount Plan	168
Reliability Performance Engineer or Analyst	1
Energy Manangement System Administrators	2
2018 Headcount Plan	171
Energy Manangement System Administrator - Retirement	-1
Engineers	2
2019 Headcount Plan	172

PPL companies

Headcount & Employee Expense

2014-2019 Headcount

Business Unit Name	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Total Full Time & Part Time Headcount (without interns)	148	155	157	160	163	164
Employee Related Expenses	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
1.) Training & Development	$298,897	$368,156	$375,420	$382,944	$347,334	$354,281
2.) Travel	$261,992	$352,236	$359,280	$366,468	$373,797	$381,273
3.) Meals and Expenses	$140,255	$160,204	$163,428	$166,716	$170,050	$173,451
4.) Employee Recognition	$6,859	$6,000	$6,000	$6,000	$6,000	$6,000
5.) Employee Dues and Memberships	$3,503	$3,000	$3,000	$3,000	$3,000	$3,000
TOTAL	**$711,506**	**$889,596**	**$907,128**	**$925,128**	**$900,182**	**$918,005**
Average Employee Expense per number of employees	**$4,807**	**$5,739**	**$5,778**	**$5,782**	**$5,523**	**$5,598**

PPL companies

2013-2019
Other Balance Sheet Costs
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Stores Expense							
Labor							
Non labor							
Total							
Local Engineering							
Labor	6,099	5,172	7,848	8,215	8,552	8,927	9,300
Non labor	985	-	-	-	-	-	-
Total	7,084	5,172	7,848	8,215	8,552	8,927	9,300
Other Balance Sheet							
Labor							
Non labor							
Total							
Total Other Costs							

PPL companies

PPL companies

Power Generation

2015 Business Plan

September 17, 2014

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  - *Capital*
  - *Headcount*
  - *Key Performance Indicators*
- Plan Risks
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PPL companies

Plan Highlights

- Additional generation capacity - Cane Run Unit 7 CCGT scheduled for commercial operation May 1, 2015 and a second CCGT planned for May 1, 2021 at Green River
- Planned retirements of coal generating units at Cane Run (April 2015) and Green River (April 2016)
- Major investment and integration of environmental compliance control equipment
- Generation forecast for the planning period assumes continued trend of more gas fired production based on current projections for gas prices
- Required landfill expansion at Ghent, Brown and Trimble stations
- Increased resource needs to meet and maintain compliance with incremental regulatory requirements
- Trimble County Unit 2 resolution of existing issues and warranty claims
- Brown 1 and 2 remain in the generation mix without baghouses (Nalco additive included)

PPL companies

Major Assumptions

1. Regulatory

1.1 The State of Kentucky remains regulated throughout the plan period and the Environmental Cost Recovery (ECR) and Fuel Adjustment Clause (FAC) remain in place.

1.2 Target Reserve Margin of 16%, within a range of 16% - 21%.

- Given experiences of early 2014 for the industry, the high end of the range is preferred.

1.3 Reserve sharing under the TVA Reserve Sharing Agreement is 258 MW's.

1.4 LG&E and KU remain committed to burning higher sulfur fuels.

1.5 The next ECR Filing is targeted for October 1, 2015.

1.6 Of the twelve municipal utilities served by KU, nine provided termination notices. Combined with the departure of Benham, this will be a reduction of 325 MW by May, 2019.

2. Proposed or Expected New Environmental Regulations for Air and Water

2.1 Final Cross State Air Pollution Rules (CSAPR) were issued in July 2011, with the order being stayed on December 30, 2011, and completely struck down on August 21, 2012.

- Supreme Court agreed to re-hear EPA's defense of CSAPR
- Rehearing occurred 12/10/2013.
- On April 29, 2014 the Supreme Court reversed and remanded the case back to the D.C. Circuit Court's for further proceedings
- Possibilities of future proceedings by the D.C. Circuit Court include:
  - Overturn CSAPR on other grounds not addressed by Supreme Court
  - Uphold CSAPR, but considering the original CSAPR was based on the 1997 NAAQS for Ozone, EPA may decrease the allocations to reflect the latest NAAQS for Ozone (2008)
  - CAIR allocations will remain in place until CSAPR is fully resolved (likely at least through 2015).

PPL companies

Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.2 Mercury and Air Toxics Standards (MATS) final rules take effect on April 16, 2015.

- In most cases a delay of up to one year can be applied for, moving the compliance date to April 16, 2016.
- A second, additional, year of delay can be obtained in certain hardship cases, including retirements that could adversely impact transmission reliability. None of the LKE projects are currently counting on that second year of delay, though it is possible that a request will be made for Green River 3-4.

2.3 The final National Ambient Air Quality Standards (NAAQS) rules have been issued, with one hour standards in place for NO_x and SO_2. The final attainment designations for the short term NO_x standard have been delayed for up to three years due to inadequate monitoring. Based on the new short term SO_2 standards, compliance requirements must be in place by October 2018.

- The Mill Creek Wet (WFGD) FGD project is expected to mitigate the area in Jefferson County that has been proposed as non-attainment.

2.4 The EPA issued its revised rule on PM NAAQS on December 14, 2012.

- The current annual Particular Matter standard for $(PM)_{2.5}$ of 15 ug/M^3 was lowered to 12ug/M^3.
  - This puts Jefferson and Bullitt as non-attainment.
  - The recent modifications at Gallagher Station, the shutting down of Cane Run 4, 5, and 6, and the baghouses, scrubbers, and dry sorbent injection systems at Mill Creek should mitigate concerns in Jefferson County.
  - The KyDAQ has recommended to EPA to classify Jefferson and Bullitt Counties “attainment / unclassifiable”
  - In general, on units adding baghouses, LKE should have no trouble with compliance.

Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.5 The EPA is scheduled for a 2014 re-evaluation of the 8-hour ozone standard. Due to litigation, they were prepared to issue an early revision that would have been much lower with large impacts industry wide; however, they instead decided to re-instate the 2008 NAAQS Ozone 8-hour standard.

- Non Quality Assured 2012 monitor data indicates Jefferson County as non-attainment with the 1997 and the 2008 standard.
  - Likely Case: Shutdown of Cane Run 4, 5, and 6 mitigates the issue.
  - Worst Case: SCRs are needed at Mill Creek 1 and 2 to mitigate the issue.
  - All of Kentucky except the far eastern side and Warren County currently show non-attainment with the levels of Ozone NAAQS that EPA is planning to propose in 2014.
  - The SIP revision process will target attainment by 2021.

2.6 Cane Run Coal will be retired May 1, 2015.

- Combined cycle replacement available on that date.
- Cane Run 6 will be on lay-up starting October, 2014.
- There are 23 employees expected to retire or take the severance, and 46 will be placed elsewhere.
  - 40 at Mill Creek, 2 at Trimble County, and 4 to be determined.

Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.7 Green River Coal will be retired April 16, 2016.

- This is based on a one-year extension granted by the State, that as of August, 2014 has not yet been applied for.
- A Transmission Capital Project (Matanzas) has been completed.
  - However, the impact from Big Rivers shutting down the Wilson and Coleman Units has created other issues that need to be addressed from a transmission perspective.
- There are 15 employees expected to retire or take the severance. Of those remaining, eleven will go to meter reading, one to the turbine shop, five will stay at the plant, and nine will be placed elsewhere.
  - Of the five remaining at the plant, two will provide lab support and three will be tied to Green River 5, starting July 1, 2016, on charges to the capital project.

2.8 On March 21, 2011 EPA published a final rule that identified non-hazardous secondary materials that are considered solid wastes when combusted.

- Boiler cleaning disposal by evaporation in the boiler will be prohibited unless we are permitted as a “commercial and industrial solid waste incinerator”.

- State of Kentucky has determined they need a SIP revision and have provided an opinion that it will not be in effect until 2018. This has O&M implications.

Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.9 GHG New Source Performance Standards (NSPS) for new sources.

- EPA announced proposed rule on 09/20/2013 and published the proposal in the Federal Register on 01/08/2014.
  - Clean Air Act requires EPA to take final action on proposed rule within one year of publication, by January 8, 2015.
- Only addresses CO2:
  - Limit of 1,100 lbs/MWh (gross) for new coal-fired generation.
  - Limit of 1,000 lbs/MWh (gross) for new gas-fired generation.
- Affects new units only [Coal-Fired Units, Integrated Gas Combined Cycle (IGCC)].
    - Natural Gas Fired Cane Run 7 and the future Green River 5 are the only units in the LKE fleet currently impacted.
    - Cane Run 7 NGCC emission rate estimated at 800 lbs/MWh (gross) during full load operation.
  - New simple cycle turbines only affected if at least 1/3 of maximum capacity utilized for electric generation provided to grid.

Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.10 On June 2, 2014, EPA released their proposed regulations for greenhouse gas (carbon) reductions from existing fossil-fueled electric generating units (EGUs).

- Upon publication of the proposed rule in the Federal Register (FR), the EPA will have one year to issue a final rule.
- At that point, the States will have one year to develop and submit their State Implementation Plans for EPA's approval (June 2016). They can seek a one year extension for a single State Plan or a two year extension for a multiple State Plan. The EPA will then have up to one year to approve the plans.
- Interim limits on emissions from units that are in existence or began construction prior to January 8, 2014 will be based on average emissions from 2020 – 2029 with a final limit beginning 2030.
- The limit is rate-based in units of lbs CO2/MW net, however, may be converted to mass-based (tons/year).
- The proposal is unclear on treatment of shutdown generation and new NGCC generation that begins construction after January 8, 2014.
- Absent further information to the contrary, Brown 1 and 2 remain active through the 10-year planning period.

Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.11 The 2011 ECR compliance plan settlement and CPCN were approved December 16, 2011, and will include the following air quality controls:

- A new Mill Creek 4 WFGD (December 2014).
- A new Mill Creek 3 WFGD (June 2016).
- A new Mill Creek 1 and 2 (combined) WFGD (May 2015).
- Fabric Filters on Ghent 1-4, Mill Creek 1-4, Brown 3, and Trimble County 1.
  - 2014 in-service: GH3 (June), GH4 (December), MC4 (December).
  - 2015 in-service: BR3 (April), GH1 (May), GH2 (December), MC1 (May), MC2 (May), TC1 (October).
    - The existing precipitators on Brown 3 and Ghent 1 and 2 will be removed.
  - 2016 in-service: MC3 (June).

- A PAC system for Mill Creek Unit 3 and Sorbent Injection system for Mill Creek Units 3 and 4.
  - In-service October 2016.
- The Brown 1-2 Fabric Filters were removed from the 2011 ECR plan as part of the settlement. The fabric filters are not included in the 2014 BP. Brown 1 and 2 do remain in the generation mix through the planning period, however.
  - With Nalco additive included. Injection system scheduled for September 30, 2014 completion.
  - Run times may be limited.

Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.12 Significant O&M and cost of sales (~$25M - $30M per year) will be incurred as remaining units become operational for MATS Compliance.

- Costs will begin ramping up in 2014 as units are completed.
  - Additional limestone usage at Mill Creek 1 and 2 WFGD.
  - Additional hydrated lime injection to protect bags at all baghouse installations.
- Prior to 180 days after the compliance date of April 16, 2015 (or April 16, 2016 for units that have been granted an extension), all units must have completed a boiler tune-up with specific documentation of improvements and procedures and effects on CO and NO_x.
  - EPA has intent to allow for the boiler tune-up to occur prior to the compliance date.

2.13 EPA issued the Final 316(b) rule by May 19, 2014.

- Only Mill Creek 1 will be impacted.
  - Two years of entrainment monitoring in 2015/2016.
  - State will negotiate with LG&E in 2017, with a 3-5 year implementation.
  - A cooling tower for Unit 1 is a sensitivity.

Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.14 Effluent water guideline draft proposal was issued April 19, 2013, with the final rule targeted to be issued September, 2015.

- **Timing expected to coincide with final rules on coal combustion residuals (CCR's).**
- **A Five-Year implementation period is expected, however, a mercury discharge limit of 51 ppt for all four remaining coal-fired stations as part of new KPDEs permit requirements will likely require LKE to be ahead of the EPA timeline.**
  - **Mill Creek will likely be the first plant impacted.**
- **A four-year compliance period is expected to meet the state requirements.**
- **The estimated cost is 3X higher than the 2014 BP, largely driven by the inclusion of a limit on selenium.**
  - **The estimate currently used is the mid-point of a level 1 engineering high and low range of eight different options that includes selenium.**

2.15 Ghent negotiated SO_3 (H_2SO_4) permitted emission limits with EPA in 2012.

- **The Consent Decree was "Entered" by the Court on 8/21/2013 initiating the start**

Major Assumptions

3. Expansion/Capacity

3.1 A combined cycle unit (Cane Run 7) will be added May 1, 2015 at the Cane Run location.

- 2 x 1, 640 MW Summer Net (Ownership is 78% KU, 22% LG&E).
- Replacing Cane Run Coal retired on that date.
- CPCN approval date of September, 2012.
- Expense profile based on a Long-Term Services Agreement being in place.

3.2 A second combined cycle unit (Green River 5) will be added May 1, 2021 at the Green River location.

- Ownership percentage will be 60% KU, and 40% LG&E.
- 2 x 1, 640 MW Summer Net, with other options for a comparable number of MW's being considered (i.e. two 1 X 1's).
- Expense profile based on a Long-Term Services Agreement being in place.
- Timing could move up if the municipal utilities do not end up leaving the KU system.

3.3 A 10 MW Solar Facility will be installed at the Brown Generating Station by December 31, 2016.

- Ownership percentage will be 61% KU and 39% LG&E.
- There is incremental OPEX associated with the facility.

Major Assumptions

3. Expansion/Capacity (Cont,)

3.4 Reserve margin purchases are 165 MW between May 1, 2015 and April 30, 2019.

3.5 Brown 1 and 2 are included through the planning period, but without fabric filters.

- The Nalco product, to keep mercury emissions lower, will be utilized.

3.6 The third combined cycle will not be needed until 2031, as long as Brown 1 and 2 are still active.

3.7 The five Ohio Falls units still to be rehabilitated (the other three are complete) have the following scheduled mechanical completion dates.

- Unit 1 (June 2014).
- Unit 5 with turbine coupling repair (October, 2014).
- Unit 2 (July, 2015).
- Unit 4 (February, 2017).
- Unit 8 (May, 2016).

3.8 Black start additions (for system restoration purposes) will take place in 2017 and 2018.

- Trimble County Site 2017 in-service. Engineering takes place in 2015.
- Cane Run Site 2018 in-service. Engineering takes place in 2016.

3.9 Group 3 retirements will be considered based on a Retire vs. Repair cost analysis if there is a failure.

- Group 3 consists of the older, smaller CT's.
- No Group 3 units are being retired in the plan.
  - Haefling 3 was retired in 2013.

Major Assumptions

4. Coal Combustion Residuals (CCR's)

4.1 EPA issued two proposals for public input for coal combustion residuals (CCR's) in June 2010.

- Final rules are expected on December 19, 2014 and once final rules are issued there will be a five-year implementation period with an additional two years to close existing ponds. Unlined ponds (and possibly even lined ponds) are expected to be eliminated for ash storage.
- EPA is looking to tie the timing of CCR's and effluent water (see 2.14) together.
  - Congress is working on a bi-partisan effort.
  - Expected timeframe of 2018 - 2020 on pond closures and 2017-2018 on construction of new process ponds.
  - CCR materials are used for closing ponds on all active coal facilities.
  - A designation of "Hazardous" vs. "Non-Hazardous" appears to be strongly trending toward "Non-Hazardous".
  - The designation will not change the capital plan but would reduce beneficial re-use opportunities for structural fill and gypsum for wallboard if declared "hazardous".

4.2 Trimble County Landfill and Transport.

- The projected in-service date for the transport and treatment system is September, 2017.
- The projected in-service date for the landfill is April, 2018.
  - Approval of DWM permit is in January, 2015.
  - One year litigation of permits (1/15 – 1/16)
  - Construction period of 2.75 years.

4.3 Brown Ash Pond is being converted to a landfill, with an expected in-service date of second quarter, 2016 for Phase 1.

- KYDWM permit expected third quarter, 2014.
- Construction schedule is approximately 18 months.
- All three phases will be staged concurrently.

Major Assumptions

4. Coal Combustion Residuals (CCR) (Cont.)

4.4 Ghent Landfill Phase 1 construction went in service in June, 2014.

- Transport portion of the project is trending toward an August or September, 2014 in-service date.

4.5 A new Mill Creek landfill will be in-service by December 31, 2019.

- Landfill location is 1.5 miles from Mill Creek with a 1.5 mile transport pipe conveyor.

4.6 The Cane Run MSE Wall will be completed in 4th Quarter 2014.

4.7 The Cane Run Landfill will be closed in 2016.

4.8 The Cane Run Ash pond Cap & Closure project will be completed in 2017.

4.9 All CCR Capital Projects use an annual escalation rate of 4.0%.

4.10 The pond closure projects assume that existing CCR materials from each plant can be used to fill in each pond, similar to Cane Run. If that is not allowed by rule, the estimated cost of having to instead procure top soil and clay is an additional $450M.

4.11 If CCR materials are allowed for Pond Closure, Phases II and III of the landfill projects will move further out in time relative to what is in the 10-year projections.

LG&E KU
PPL companies

Major Assumptions

5. Operational and Other

5.1 Annual escalation rates for internal labor and non-labor are as follows:

- Internal labor: 3.0%.
- Non-labor 2.0%.

5.2 The next turbine overhauls by unit are as follows:

- 2014 : Mill Creek 4, Ghent 4.
- 2015 : Ghent 1, Brown 1.
- 2016 : None scheduled.
- 2017: Brown 2, Trimble 1.
- 2018: Ghent 3, Trimble 2.
- 2019: Ghent 2, Brown 3, Mill Creek 3.

5.3 Significant generator rewind/stator rewind dollars are included in the 2014-2017 timeframe.

- Brown 2 generator (stator and rotor) rewind in 2017 (some dollars also in 2016).
- Spare stator bars ordered and received for Ghent 2-4, Mill Creek 1-4, and TC 1 between 2010 – 2016.
    - The spare sets will be installed on MC4 in 2014, MC3 in 2019, MC2 in 2020, and MC1 in 2021.

Major Assumptions

5. Operational and Other (Cont.)

5.4 The corrosion fatigue inspection schedule is as follows:

- 2014: Ghent 4.
- 2015: Ghent 1, Mill Creek 1.
- 2016: Brown 1, Mill Creek 2, Mill Creek 4.
- 2017: Brown 2, Mill Creek 1, TC1.
- 2018: Brown 3, Ghent 1, Ghent 3, Mill Creek 4, TC2.
- 2019: Ghent 2, Mill Creek 3.

5.5 The High Energy Piping (HEP) inspection schedule is as follows:

- 2014: Ghent 3, Ghent 4, Mill Creek 4, TC2.
- 2015: Brown 1, Ghent 1, Ghent 2, Mill Creek 3.
- 2016: Brown 3, Mill Creek 2, TC2.
- 2017: Brown 2, Mill Creek 1, TC1.
- 2018: Brown 1, Ghent 1, Ghent 3, Ghent 4, Mill Creek 2, Mill Creek 3.
- 2019: Brown 2, Brown 3, Ghent 2, Mill Creek 1, Mill Creek 2, TC1.

5.6 The fuel procurement plan is pushing toward higher chlorine ILL. Basin fuels, which will drive burner modifications on at least two Mill Creek units and two Ghent units.

- Permit changes may also be needed.

Major Assumptions

5. Operational and Other (Cont.)

5.7 Targets for percentage of coal hedged in the 2015 Business Plan (in the year 2015) are as follows:

	Coal
2015	95%-100%.
2016	80%-90%.
2017	40%-90%.
2018	30%-70%.
2019	10%-50%.
2020	0%-30%.

- Targets for natural gas will follow a similar progression, but will build up slowly over time and will be comparable by the year 2018.

5.8 Based on a range of $4.00 to $6.00 per MMBTU, Can Run 7 natural gas usage can range from usage of 34 million MCF at $4.00 gas, to 16 million MCF at $6.00 gas. This can change coal burn by 1.7 million tons per year.

Major Assumptions

5. Operational and Other (Cont.)

5.9 Combustion turbine outages in the plan:

- **Dollars are split between O&M and capital based on the estimated scope of work that is reconditioning (expense – approximately 10%) vs. new parts (capital – approximately 90%).**
- **The first set of hot gas path inspections for Trimble CT's are complete as of the Spring, 2013. The cycle starts again with one unit in 2016, two units in 2017, two units in 2018, and one unit in 2019.**
- **Brown C inspections by unit are as follows:**
  - **Unit 10 in 2015.**
  - **Unit 6 in 2017.**
  - **Unit 7 in 2018.**
  - **Unit 11 in 2020.**
  - **Unit 5 in 2021.**
  - **Unit 8 in 2024.**
  - **Unit 9 in 2030.**
- **The expiration date for the Brown 6 and 7 Long-Term Services Agreements (LTSA) is October 1, 2016 based on the 13-year criteria.**
- **The CT component outages for Cane Run 7 are a Combustion Inspection late 2016, Hot Gas Path Inspection (HGPI) 2019, Combustion Inspection 2021, and a major in 2022 (HGPI and turbine overhaul).**
  - **Cane Run 7 CT's are covered under a signed LTPC.**
  - **The turbine/generator overhaul will be every seven years, with the first one in 2022.**

5.10 CIP Version 5 will have an effective date of April 1, 2016.

Major Assumptions

5. Operational and Other (Cont.)

5.11 Complete demolition of Paddy's Run Coal Plant will take place 2015-2016, and complete demolition of Canal Station 2016-2017. Paddy's stacks were removed in 2013.

5.12 Complete demolition of Pineville and Tyrone Power Plants will take place between 2020-2022.

5.13 Expected write-offs to expense include:

- Cane Run M&S $8M (2015).
- Green River M&S $2M (2015).
- Ghent Ash Handling M&S $1M (2014).
- Mill Creek FGD M&S $1.5M (2016).

5.14 The proysm run dated August 22, 2014 is the official generation forecast for the 2015 Business Plan.

Financial Review – Prior Plan to Plan Expectation Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OPEX (O&M and BTL):					
Prior Plan Amount	245,305	234,688	243,051	267,478	286,448
Adjustments/Transfers:					
Safety Reorganization	(1,082)	(1,182)	(1,209)	(1,176)	(1,210)
Move Project Dev to PE	(584)	(595)	(608)	(621)	(635)
MC OPEX to ECR	(688)	(1,221)	(1,329)	(1,356)	(1,383)
Delay GR closing to 2016	11,800	7,000			
Delay GR5 to 2021				(11,037)	(19,328)
BP Efficiency Savings	(3,574)	(5,910)	(5,774)	(5,849)	(3,022)
Current Plan Expectation	251,177	232,780	234,130	247,439	260,869

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
GMEXP (OCOS) ECR:					
Prior Plan Amount	44,800	59,098	66,122	67,220	68,704
Adjustments/Transfers:					
MC OPEX to ECR	688	1,221	1,329	1,356	1,383
Current Plan Expectation	45,488	60,319	67,451	68,576	70,087
GMEXP (OCOS) NON ECR:					
Prior Plan Amount	36,896	35,691	37,532	37,672	38,898
Adjustments/Transfers:					
Current Plan Expectation	36,896	35,691	37,532	37,672	38,898

PPL companies

Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M Expenses Only							
Company Labor	89,405	94,115	97,766	96,428	95,791	98,224	100,123
Resident Contractors	23,335	25,613	23,282	21,187	21,353	21,922	22,525
Maintenance	64,117	65,635	67,457	60,392	59,947	65,726	61,775
Outages	20,264	33,353	36,431	30,258	34,905	34,356	55,404
Operations	21,252	24,394	25,585	23,311	23,156	24,438	24,908
Subtotal O&M Expense	218,373	243,110	250,523	231,578	235,152	244,666	264,734
Other Income/Expense* * (see OIE slide for detail)	932	648	655	665	675	689	702
Total Income Statement items	219,305	243,758	251,177	232,243	235,827	245,355	265,436

PPL companies

Financial Performance - OPEX

2013-2019 Other Income/Expenses (incl. BTL)
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OIE/BTL Expenses Only:							
Contributions	297	265	296	295	300	306	312
Employee Recognition	178	135	107	111	116	118	120
Meals and Meetings Exp.	142	78	60	64	65	66	68
Safety Awards	12	28	29	29	30	30	31
Other	303	142	163	166	165	168	171
Total OIE / BTL Expense	932	648	655	665	675	689	702

PPL companies

2015-2019 O&M / Other Expense Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Current Plan Expectation	251,177	232,780	234,130	247,439	260,869
Drivers:					
Ghent outage scope revisions	(3,440)	(3,405)	(1,664)	(5,324)	(780)
Additional TC2 outage scopes	1,500		1,500		
Timing TC2 outage				(2,954)	2,223
CR7 Outage revisions	895	1,787	1,747	968	4,024
Other Outage schedule scope and timing updates	184	(419)	(636)	466	912
Brown Solar		-	225	225	225
True up CR inventory write off	973	-	-	-	-
Labor - true up CR severance	(1,395)	-	-	-	-
Labor	(1,088)	(16)	2,153	1,203	131
Changes in Maintenance and Operations expense	2,371	1,515	(1,628)	3,332	(2,168)
Current Plan	251,177	232,243	235,827	245,355	265,436
Variance - Fav (Unfav)	**0**	**537**	**(1,697)**	**2,085**	**(4,567)**

Financial Performance

2013-2019 Margin Expenses / Cost of Sales/Mechanism ($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Gross Margin Elements							
ECR							
Labor	174	192	1,591	2,066	2,116	2,163	2,257
Resident Contractors (primarily landfill)	1,171	2,054	2,680	3,525	3,545	4,161	4,447
Environmental Maint & Ops	62	128	96	248	103	105	107
ECR Maintenance SDRS	(45)	176	604	1,092	1,185	801	817
ECR Baghouse Maintenance	-	118	2,210	3,921	4,004	4,084	4,166
ECR Activated Carbon	-	850	9,331	16,029	16,905	17,760	17,738
ECR Landfill Operations	-	944	5,383	5,852	6,396	8,793	8,996
ECR Fly Ash Disposal	344	445	540	552	569	586	603
ECR Nox Emission Allowances	1	155	-	-	-	-	-
ECR Nox Reduction Reagent	673	605	465	477	523	590	534
ECR Other Waste Disposal	41	490	1,350	1,350	1,350	1,354	1,358
ECR Sorbent Injection Maintenance	235	474	468	565	580	591	603
ECR Sorbent Injection Operation	48	71	84	88	92	94	96
ECR SO2 Emission Allowances	95	42	30	30	30	30	30
ECR Sorbent Reactant - Reagent Only	12,166	13,173	15,007	16,350	18,404	19,225	19,178
Total ECR	14,964	19,918	39,840	52,144	55,801	60,337	60,928

Financial Performance

2013-2019 Margin Expenses / Cost of Sales/Non Mechanism ($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Gross Margin Elements							
Non-ECR							
Resident Contractors	579	347	648	664	682	695	709
Environmental Maint & Ops	6	311	-	-	-	-	-
Mercury Monitors Operations	166	186	-	-	-	-	-
Activated Carbon	1,241	1,895	2,763	2,808	3,024	2,751	3,089
Other Waste Disposal	2,070	1,896	1,187	922	959	987	1,016
NOx Emission Allowances	284	34	73	25	-	-	-
NOx Reduction Reagent	7,866	8,431	8,691	9,079	9,675	9,177	9,050
Scrubber Reactant Ex	23,485	23,942	18,180	17,749	18,514	19,607	20,236
SO2 Emission Allowances	0	144	85	18	8	9	9
Sorbent Injection Operation	170	(30)	-	-	-	-	-
Sorbent Reactant - Reagent Only	1,556	1,902	5,576	6,839	6,208	5,591	6,189
Total Non-ECR	37,423	39,057	37,202	38,104	39,070	38,816	40,297
Total Gross Margin	52,387	58,974	77,042	90,249	94,871	99,153	101,226

PPL companies

2015-2019 Margin/Cost of Sales Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
ECR Current Plan Expectation	45,488	60,319	67,451	68,576	70,087
Drivers:					
Activated Carbon (Brown using Nalco product only)	(2,423)	(6,693)	(7,457)	(6,641)	(7,204)
Change in SAM Mitigation (Sorbent Reagent costs)	(3,266)	(3,457)	(3,139)	(2,680)	(3,246)
ECR Maintenance SDRS (MC)	769	1,219	1,248	894	2,319
Lower Cost estimates for landfills	(1,103)	44	(2,348)	(269)	(172)
Other Small Various Puts and Takes	375	714	45	456	(855)
ECR Current Plan	39,840	52,144	55,801	60,337	60,928
Variance	**5,648**	**8,174**	**11,650**	**8,240**	**9,159**
Non-ECR CurrentPlan Expectation	36,896	35,691	37,532	37,672	38,898
Drivers:					
Scrubber Reactant	1,359	2,106	1,842	3,304	3,474
Lower price of Activated Carbon	(1,858)	(1,566)	(1,855)	(2,531)	(2,299)
NOX Reactant higher cost projections	(1,780)	(1,164)	(732)	(1,316)	(1,934)
Change in SAM Mitigation (Sorbent Reagent costs)	2,976	3,480	2,748	2,154	2,624
Other Small Various Puts and Takes	(391)	(443)	(465)	(466)	(466)
Non-ECR Current Plan	37,202	38,104	39,070	38,816	40,297
Plan To Plan Variance	**(306)**	**(2,413)**	**(1,538)**	**(1,145)**	**(1,400)**
Grand Total Gross Margin Expense	**77,042**	**90,249**	**94,871**	**99,153**	**101,226**

PPL companies

2013-2019 Capital Breakdown (w COR) – Accrual Basis ($000)

	2013	2014 FC	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Environmental Mechanism (ECR)							
140375 BR3 Spare HWRS Pump	394	-	403	-	-	-	-
135123 MC2 PJFF BC 2018	-	-	-	-	1,290	336	-
135122 MC1 PJFF BC 2018	-	-	-	-	-	1,380	300
135102 BR3 PJFF BC 2018	-	-	-	-	-	1,839	-
135124 MC3 PJFF BC 2018	-	-	-	-	-	-	1,936
135245LGE TC2 PJFF B&C 2017	-	-	-	-	-	2,077	-
135236 TC1 PJFF B&C 2018	-	-	-	-	-	-	2,117
135120 MC4 PJFF BC 2017	-	-	-	-	-	2,253	-
133939 BR3 SCR Catalyst	-	518	1,954	-	-	-	-
144121 MC1 Environmental Spares	-	-	1,375	1,125	-	-	-
144122 MC2 Environmental Spares	-	-	1,375	1,125	-	-	-
144123 MC3 Environmental Spares	-	-	-	2,500	-	-	-
144124 MC4 Environmental Spares	-	-	2,500	-	-	-	-
135281 GH3 PJFF BC 2017	-	-	-	-	-	2,704	-
135283 GH4 PJFF BC 2017	-	-	-	-	2,704	-	-
135279 GH2 PJFF BC 2018	-	-	-	-	-	-	2,758
135277 GH1 PJFF BC 2018	-	-	-	-	-	2,763	-
136640 GS RD Hg Contrl LGE	-	-	-	4,000	-	-	-
	394	518	7,607	8,750	3,994	13,352	7,111
New Generation - CR7 Inventory	642	1,358	4,830	-	-	-	-
Required >$3M							
132921 MC3 Reheater	3,398	(9)	-	-	-	-	-
132804 MC3 BURNERS 2013	3,511	340	-	-	-	-	-
112767 MC Landfill Expansion	133	456	400	1,975	263	263	275
137600 CR Plant Closure	-	-	4,800	3,800	-	-	-
144536 CR7 NGCC CI (2016)	-	-	-	10,333	-	-	-
144542 CR7 NGCC HGP (2019)	-	-	-	-	-	-	27,034
All other less than $3M	22,231	9,179	6,921	11,575	4,971	7,985	6,600
	29,273	9,966	12,121	27,683	5,234	8,248	33,909

PPL companies

2013-2019 Capital Breakdown (w COR) – Accrual Basis ($000)

		2013	2014 FC	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
High Risk >$3M								
126593LGE	TC CT HGPI # 6	3,917						
127642	MC4 Burners	4,254	2,850	100	-			
131116	GH Stacker Track Repl 1/2 East	4,644	43	-	-			
123907	BRCT9 C Inspection 11	6,398	(24)	-	-			
140179	GH1 Air Heater Baskets	-	-	-	-	1,552	1,552	-
133938	BR1 Cooling Tower Rebuild	-	1,309	1,960	-	-	-	-
137024	GH 138kv Switchgear Upgrade	-	-	-	600	2,712	-	-
144722	BR3 HP-IP Blading	-	-	-	-	-	662	2,651
132924	MC4 Reheater	2,246	4,019	-	-	-	-	-
133971	BR2 Cooling Tower Rebuild	-	-	-	-	4,206	-	-
132901	MC4 Cooling Tower Fill	-	4,450	50	-	-	-	-
133741	GH3 Main Condenser Retube	-	-	-	-	3,104	1,583	-
132951	MC3 Condenser 2014	-	-	-	-	500	1,000	3,500
144450	BR3 Economizer Repl	-	-	-	-	-	2,000	3,200
132001	TC CT HGP Insp #2	-	-	-	-	5,218	-	-
132000	TC CT HGP Insp #1	-	-	-	5,218	-	-	-
132002	TC CT HGP Insp #3	-	-	-	-	5,374	-	-
131980	GH3 Primary SH Tube Repl	-	-	-	-	2,483	3,052	-
131975	GH4 Burner Repl	2,451	5,269	302	-	-	-	-
123910	BRCT10 C Inspection 12	-	1,212	6,273	-	-	-	-
131974	GH 3 Burner Repl	-	-	-	100	2,277	6,155	-
131972	BRCT7 C Inspection	-	-	-	-	-	12,400	-
143864	PR Gas Pipe Line	-	250	14,750	-	-	-	-
123906	BRCT6 C Inspection 13	-	-	-	-	19,000	-	-
	All other less than $3M	33,329	33,413	29,043	13,388	20,000	16,063	28,983
		57,239	52,790	52,478	19,305	66,426	44,466	38,334

PPL companies

2013-2019 Capital Breakdown (w COR) – Accrual Basis ($000)

		2013	2014 FC	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
All Other >$3M								
139878	MC3 TURB MISC	-	-	-	-	-	-	3,000
142399	MC3 Gen Stator Bar Install	-	-	-	-	-	-	3,200
139722	MC2 Gen Stator Bar Purchase	2,916	305	2,906	-	-	-	-
135638	MC3 Stator Bars	2,840	4		-	-	-	-
135640	MC1 Stator Bars	2,970	308	2,940	-	-	-	-
143636	MC3 Turbine IP Diaph 8-12	-	-	-	-	-	-	3,500
137268	GH2 Retube Main Cond 2019	-	-	-	-	-	1,035	2,793
144311	GH3 Upper Econ Upper Bank	-	-	-	-	807	3,175	-
143637	MC3 Turbine L-0 Buckets	-	-	-	-	-	1,000	3,000
133102	GS GE 345kV Spr LGE	-	-	1,303	3,040	-	-	-
139871	MC3 INT SH PENDANTS	-	-	-	-	-	1,475	3,000
136097	DX Dam Leakage Rem Phase II	-	-	6,000	-	-	-	-
144302	GH2 4kv Switchgear	-	-	-	-	249	4,408	4,174
131986	GH3 Turb Eff Upgr	-	-	-	1,035	3,104	8,276	-
132005	TC CT HGP Insp #6	-	-	-	-	-	-	3,399
132004	TC CT HGP Insp #5	-	-	-	-	-	3,549	-
132003	TC CT HGP Insp #4	-	-	-	-	-	3,549	-
131972	BRCT7 C Inspection	-	-	-	-	-	7,600	-
	All Other	15,743	24,765	37,508	25,068	31,876	38,185	36,596
		24,469	25,382	50,657	29,142	36,036	72,250	62,662
Total Capital		**112,017**	**90,014**	**127,692**	**84,880**	**111,691**	**138,316**	**142,017**

PPL companies

2015-2019
Capital Reconciliation (w COR) –Accrual Basis
($000)

		2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
	2014 Capital BP	**107,606**	**76,973**	**110,822**	**150,926**	**NA**
Increases/(Decreases) from Prior Plan > $3.0m						
131955	BR2 Gen Rewind	-	(2,333)	(4,667)	-	
139825	BR3 HP-IP Repl	-	-	-	(9,975)	
144450	BR3 Economizer Repl	-	-	-	2,000	
144722	BR3 HP-IP Blading	-	-	-	662	
123906	BRCT6 C Inspection 13	-	-	19,000	(19,000)	
131972	BRCT7 C Inspection	-	-	-	20,000	
144536	CR7 NGCC CI (2016)	-	10,333	(10,333)	-	
144542	CR7 NGCC HGP (2019)	-	-	-	-	
136097	DX Dam Leakage Rem Phase II	6,000	-	(2,850)	-	
133402	GH4 Condensate Polisher	-	-	-	-	
135645	GH3 RH Outlet Header Repl	-	-	(1,852)	(4,115)	
137473	GH3 Finishing SH Repl 2018	-	-	(1,465)	(4,089)	
140219	GH2 Generator Refurbishment	-	-	-	-	
144302	GH2 4kv Switchgear	-	-	249	4,408	
144311	GH3 Upper Econ Upper Bank	-	-	807	3,175	
131980	GH3 Primary SH Tube Repl			2,483	583	
134561	PR13 Hot Gas Path Inspection	-	-	-	(6,120)	
143864	PR Gas Pipe Line	14,750	-	-	-	
124088	MC GPP Upgrade	-	-	-	(2,200)	
132961	MC2 DCS 2018	-	-	(700)	(4,350)	
132963	MC3 DCS 2019	-	-	-	-	
132965	MC4 DCS 2018	-	-	(2,000)	(3,050)	
133000	MC3 Circ Water Line	-	-	150	-	
139718	MC4 Inter SH Pendants	-	-	(1,500)	(2,875)	
143636	MC3 Turbine IP Diaph 8-12	-	-	-	-	
143637	MC3 Turbine L-0 Buckets	-	-	-	1,000	
137595LGE	TC INSTALL CONVEYOR AND HOPPER	-	-	-	(382)	
140597LGE	TC GAS IGNITION FUEL	(3,134)	-	-	-	
136640	GS RD Hg Contrl LGE	(4,000)	4,000			
	All Other Changes < ± $3.0m	6,469	(4,093)	3,547	11,719	
	2015 Capital BP	**127,692**	**84,880**	**111,691**	**138,316**	

LG&E KU
PPL companies

Financial Performance

2013-2019 Headcount

Department[1]	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Mill Creek[2]	207	207	245	240	235	227	227
Trimble County/CTs	149	160	160	162	162	169	169
Cane Run/Ohio Falls	113	113	50	52	50	49	48
Ghent	208	214	221	228	226	226	226
Brown/Dix/Tyrone	140	143	144	143	142	141	140
Green River	41	40	40	5	5	5	5
Generation Services	49	53	55	58	59	59	60
Commercial Operations	44	52	45	45	45	45	43
Other Generation Support	10	11	13	18	19	14	14
Stranded Employees		-	4	7	2	1	1
Interns/temps	9	15	13	13	13	13	13
TOTAL	**970**	**1,008**	**990**	**971**	**958**	**949**	**946**
From 2014 Business Plan[3]		1,029	994	954			
Variance to 2014 Business Plan		-21	-4	17			

Year to Year Increases (Decreases)	2014	2015	2016	2017	2018	2019
1.) Plant closures[4]		-23	-26			
2.) Maintenance /Operational	26	3	5	-13	-16	-1
3.) Compliance – NERC, FERC, CIP, etc.						
4.) EPA/Environmental			1		7	
5.) Administrative/Corporate	12	2	1			-2
TOTAL	**38**	**-18**	**-19**	**-13**	**-9**	**-3**

Contractor Offsets By Year: (New hire reducing contractor use)	-	-	-	-	-	-

[1] 2013 restated to reflect Safety reorg and PD move to PE in 2014

[2] Includes CR displaced employees moving to MC beginning in 2015

[3] 2014BP restated for Safety Re-org; PD move to PE; and delay in GR closure

[4] Includes 11 moving to metering in 2016 from GR

Operational Performance

Key Performance Indicators

KPI	2013 Year End	2014 Forecast*	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Generation (Twh)[1]	34.9	35.1	34.6	35.1	35.1	35.4	34.7
EAF (Steam)	81.4%	82.6%	84.1%	85.7%	86.8%	85.4%	84.2%
EFOR (Steam)	7.7%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Controllable Cost ($M)[2]	$271.7	$302.7	$328.2	$322.5	$330.7	$344.5	$366.7
Controllable Cost/mwh[2]	$ 7.33	$ 8.20	$ 8.95	$ 8.68	$ 8.89	$ 9.22	$ 9.98
Recordable Injuries[3]	1.92	2.98	1.70	1.70	1.70	1.70	1.70
Lost Workday Case Rate[4]	0.11	0.37	0.26	0.26	0.26	0.26	0.26

[1] Steam Generation includes 75% of Trimble County 1 and 2.

[2] Controllable Costs include Utility O&M, Other Cost of Sales, and Below-the-Line expenses.

[3] The 2014 forecast for RIIR is the July YTD value (includes hearing loss)

[4] The 2014 forecast for Lost Workday Case Rate is the July YTD value.

**2014 Forecast is from the 7&5 forecast.

PPL companies

Plan Risks

- *Any subsequent changes to approved or proposed environmental regulations will impact the investment, construction and implementation of new systems 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 the major investment in new environmental compliance systems is tied to an extremely aggressive schedule that may impact normal operations of existing plants and could require changes to the outage planning schedule for tie in processes*
- *Availability of equipment and construction resources for major environmental compliance investment across the industry could lead to higher prices and impacts to planned schedule of completion*
- *Expansion of generating capacity and other generation changes consistent with approved integrated resource plan must be balanced with efforts to address transmission system load requirements. Additionally, the timing of retired coal and new CCGT availability will be critical*

PPL companies

Appendix

PPL companies

2013-2019
Year over Year Walk Forward
OPEX and Other Expense ($000)

2013 Actual	219,305
Labor	4,710
Resident contractors	2,278
Inventory Write offs Ghent	895
Outages	13,089
Maintenance	623
Other	2,858
2014 FC	243,758
Labor (excl CR)	4,840
CR severance	2,514
MC labor moved to ECR	(769)
MC Scrubber costs moved to ECR from OPEX	(688)
Inventory Write offs (CR)	8,973
CR labor net of CR7 labor	(2,933)
CR Resident Contractors	(2,837)
Inventory Write offs Ghent	(895)
Outages	3,078
Maintenance	(5,567)
Other	1,703
2015 Budget	251,177
Labor (excl CR and GR)	3,505
GR severance	1,700
GR retirement labor	(2,445)
GR retirement non labor	(4,370)
CR severance	(2,514)
CR labor net of CR7 labor	(1,584)
CR Resident Contractors	(1,957)
MC Scrubber costs moved to ECR from OPEX	(533)
Inventory Write offs (GR)	1,600
Inventory Write offs (CR)	(8,973)
Inventory Write offs (MC)	1,455
Outages (excl GR)	(5,173)
Maintenance (excl GR)	199
Other	156
2016 Plan	232,243

2016 Plan	232,243
Labor (excl GR)	2,703
GR severance	(1,700)
GR retirement labor	(1,640)
GR retirement non labor	(2,305)
Inventory Write offs (GR)	(1,600)
Inventory Write offs (MC)	(1,455)
Outages (excl GR)	4,947
Maintenance (excl GR)	3,262
Other	1,373
2017 Plan	235,827
Labor	2,432
Outages	(548)
Maintenance	5,778
Other	1,865
2018 Plan	245,355
Labor	1,899
Outages	21,048
Maintenance	(3,951)
Other	1,086
2019 Plan	265,436

PPL companies

2013-2019
Year over Year Walk Forward
GMEXP / Cost of Sales ($000)

ECR	
2013 Actual	14,964
Landfill Operations (Ghent)	944
Other	4,010
2014 FC	19,918
MC Scrubber costs moved to ECR from OPEX	688
Activated Carbon (MC, Ghent)	8,480
Baghouse Maintenance	2,092
Landfill Operations (Ghent and Brown)	5,065
Other	3,597
2015 Budget	39,840
MC Scrubber costs moved to ECR from OPEX	533
Activated Carbon (MC, Ghent, TC)	6,698
Sorbent reactant (Hydrated Lime)	1,343
Baghouse Maintenance	1,711
Landfill Operations (Ghent and Brown)	1,314
Other	705
2016 Plan	52,144
Activated Carbon (MC, Ghent, TC)	877
Landfill Operations (Ghent, Brown, TC)	561
Baghouse Maintenance	83
Sorbent reactant (Hydrated Lime)	2,054
Other	82
2017 Plan	55,801
Activated Carbon (MC, Ghent, TC)	855
Landfill Operations (Ghent, Brown, TC)	3,013
Sorbent reactant (Hydrated Lime)	821
Other	(153)
2018 Plan	60,337
Sorbent reactant (Hydrated Lime)	(47)
Landfill Operations (Ghent, Brown, TC)	489
Other	150
2019 Plan	60,928

Non Mechanism	
2013 Actual	37,423
Scrubber reactant	457
Activated Carbon	654
Other	522
2014 FC	39,057
Scrubber reactant	(5,762)
Activated Carbon	868
NOX reduction reagant	260
Sorbent reactant	3,674
Other	(895)
2015 Budget	37,202
Scrubber reactant	(431)
Sorbent reactant	1,263
Other	70
2016 Plan	38,104
Scrubber reactant	765
Sorbent reactant	(631)
Other	831
2017 Plan	39,070
Scrubber reactant	1,093
Activated Carbon	(273)
Other	(1,073)
2018 Plan	38,816
Scrubber reactant	629
Activated Carbon	338
Other	514
2019 Plan	40,297

2014-2019
Headcount progression

2014 Headcount 7/31/14 (including interns)	1,012
Interns	(13)
Plant Operations (all plants)	4
Commercial Operations (O&M)	3
Engineering Support	2
2014 Headcount FC	1,008
Interns	(2)
Cane Run Retirement	(23)
Plant Operations (all plants)	6
Commercial Operations (O&M)	(1)
Engineering Support	2
2015 Headcount Budget	990
Green River Retirement	(15)
GR employees move to metering	(11)
Environmental (TC CCR)	1
Plant Operations	2
Engineering Support	3
Administrative Support	1
2016 Headcount Plan	971
Plant Operations	(14)
Engineering Support	1
2017 Headcount Plan	958
Environmental (TC CCR)	7
Plant Operations (retirements)	(16)
2018 Headcount Plan	949
Plant Operations (retirements)	(3)
2019 Headcount Plan	946

Headcount & Employee Expense

Business Unit Name	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Total Full Time & Part Time Headcount (without interns)	993	977	958	945	936	933

Employee Related Expenses ($000)	2014	2015	2016	2017	2018	2019
1.) Training & Development	$ 871	$ 823	$ 865	$ 872	$ 915	$ 927
2.) Travel	359	463	392	360	368	405
3.) Meals and Expenses	206	126	135	137	140	163
4.) Employee Recognition	129	107	111	116	118	120
5.) Employee Dues and Memberships	2	-	-	-	-	-
TOTAL	**$ 1,567**	**$ 1,519**	**$ 1,503**	**$ 1,485**	**$ 1,541**	**$ 1,615**

Average Employee Expense per number of employees	**$1,578**	**$1,555**	**$1,569**	**$1,571**	**$1,646**	**$1,731**

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2013-2019
Other Balance Sheet Costs
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Stores Expense							
Labor	2,821	2,600	3,313	3,244	3,340	3,084	3,039
Non labor	1,052	406	-	-	-	-	-
Total	3,873	3,007	3,313	3,244	3,340	3,084	3,039
Local Engineering							
Labor	39	16	-	-	-	-	-
Non labor	151	27	-	-	-	-	-
Total	190	43	-	-	-	-	-
Total Other Costs	4,063	3,050	3,313	3,244	3,340	3,084	3,039

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Project Engineering

2015 Business Plan

September 17, 2014

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Plan Highlights

- **Project Engineering's plan contains a net increase of $383M for 2015-2019, plan over plan.**
- **Reductions include:**
  - **The delay of GR5 from 2018 to 2021 resulted in a $83M reduction.**
  - **CCR Ruling (pond closures) reduced by $127M due to shift to 2020.**
  - **Net decrease of $15M to Environmental Air Compliance projects.**
- **Increases include:**
  - **Effluent Water increased $486M due to new estimates from C2HMHill.**
  - **Trimble County CCR increased $42M due to refining of estimates due to permitting delays and layout changes.**
  - **Addition of Brown Solar $35M.**
  - **Brown CCR, $25M, due to Main Ash Pond Closure addition and Ghent CCR, $15M, due to maintenance costs of Phase IA and delay of Phase IB.**

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Major Assumptions

1. Regulatory

1.1 The State of Kentucky remains regulated throughout the plan period and the Environmental Cost Recovery (ECR) and Fuel Adjustment Clause (FAC) remain in place.

1.2 Target Reserve Margin of 16%, within a range of 16%-21%.

- Given experiences of early 2014 for the industry, the high end of the range is preferred.

1.3 Reserve sharing under the TVA Reserve Sharing Agreement is 258 MW's.

1.4 LG&E and KU remain committed to burning higher sulfur fuels.

1.5 The next ECR Filing is targeted for October 1, 2015.

1.6 Of the twelve municipal utilities served by KU, nine provided termination notices. Combined with the departure of Benham, this will be a reduction of 325 MW by May, 2019.

Major Assumptions

2. <u>Proposed or Expected New Environmental Regulations for Air and Water</u>

2.1 Final Cross State Air Pollution Rules (CSAPR) were issued in July 2011, with the order being stayed on December 30, 2011, and completely struck down on August 21, 2012.

- **Supreme Court agreed to re-hear EPA's defense of CSAPR**
- **Rehearing occurred 12/10/2013.**
- **On April 29, 2014 the Supreme Court reversed and remanded the case back to the D.C. Circuit Court's for further proceedings**
- **Possibilities of future proceedings by the D.C. Circuit Court include:**
  - **Overturn CSAPR on other grounds not addressed by Supreme Court**
  - **Uphold CSAPR, but considering the original CSAPR was based on the 1997 NAAQS for Ozone, EPA may decrease the allocations to reflect the latest NAAQS for Ozone (2008)**
  - **CAIR allocations will remain in place until CSAPR is fully resolved (likely at least through 2015).**

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Major Assumptions

2. <u>Proposed or Expected New Environmental Regulations for Air and Water (Cont.)</u>

2.2 **<u>M</u>ercury and <u>A</u>ir <u>T</u>oxics <u>S</u>tandards (MATS) final rules take effect on April 16, 2015.**

- **In most cases a delay of up to one year can be applied for, moving the compliance date to April 16, 2016.**
- **A second, additional, year of delay can be obtained in certain hardship cases, including retirements that could adversely impact transmission reliability. None of the LKE projects are currently counting on that second year of delay, though it is possible that a request will be made for Green River 3-4.**

2.3 **The final National Ambient Air Quality Standards (NAAQS) rules have been issued, with one hour standards <u>in place</u> for NO_x and SO_2. The final attainment designations for the short term NO_x standard have been delayed for up to three years due to inadequate monitoring. Based on the new short term SO_2 standards, compliance requirements must be in place by October 2018.**

- **The Mill Creek Wet (WFGD) FGD project is expected to mitigate the area in Jefferson County that has been proposed as non-attainment.**

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Major Assumptions

2. <u>Proposed or Expected New Environmental Regulations for Air and Water (Cont.)</u>

2.4 The EPA issued its revised rule on PM NAAQS on December 14, 2012.

- The current annual Particular Matter standard for (PM) $_{2.5}$ of 15 ug/M^3 was lowered to 12ug/M^3.
  - This puts Jefferson and Bullitt as non-attainment.
  - The recent modifications at Gallagher Station, the shutting down of Cane Run 4, 5, and 6, and the baghouses, scrubbers, and dry sorbent injection systems at Mill Creek should mitigate concerns in Jefferson County.
  - The KyDAQ has recommended to EPA to classify Jefferson and Bullitt Counties "attainment / unclassifiable"
  - In general, on units adding baghouses, LKE should have no trouble with compliance.

2.5 The EPA is scheduled for a 2014 re-evaluation of the 8-hour ozone standard. Due to litigation, they were prepared to issue an early revision that would have been much lower with large impacts industry wide; however, they instead decided to re-instate the 2008 NAAQS Ozone 8-hour standard.

- Non Quality Assured 2012 monitor data indicates Jefferson County as non-attainment with the 1997 and the 2008 standard.

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Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

- **Likely Case: Shutdown of Cane Run 4, 5, and 6 mitigates the issue.**
- **Worst Case: SCRs are needed at Mill Creek 1 and 2 to mitigate the issue.**
- **All of Kentucky except the far eastern side and Warren County currently show non-attainment with the levels of Ozone NAAQS that EPA is planning to propose in 2014.**
- **The SIP revision process will target attainment by 2021.**

2.6 Cane Run Coal will be retired May 1, 2015.

- **Combined cycle replacement available on that date.**
- **Cane Run 6 will be on lay-up starting October, 2014.**
- **There are 23 employees expected to retire or take the severance, and 46 will be placed elsewhere.**
    - **40 at Mill Creek, 2 at Trimble County, and 4 to be determined.**

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Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.7 Green River Coal will be retired April 16, 2016.

- **This is based on a one-year extension granted by the State, that as of August, 2014 has not yet been applied for.**
- **A Transmission Capital Project (Matanzas) has been completed.**
    - **However, the impact from Big Rivers shutting down the Wilson and Coleman Units has created other issues that need to be addressed from a transmission perspective.**
- **There are 15 employees expected to retire or take the severance. Of those remaining, eleven will go to meter reading, one to the turbine shop, five will stay at the plant, and nine will be placed elsewhere.**
    - **Of the five remaining at the plant, two will provide lab support and three will be tied to Green River 5, starting July 1, 2016, on charges to the capital project.**

Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.8 On March 21, 2011 EPA published a final rule that identified non-hazardous secondary materials that are considered solid wastes when combusted.

- Boiler cleaning wastewater disposal by evaporation in the boiler will be prohibited unless we are permitted as a "commercial and industrial solid waste incinerator".
- State of Kentucky has determined they need a SIP revision and have provided an opinion that it will not be in effect until 2018.
  - This has O&M implications.

2.9 GHG New Source Performance Standards (NSPS) for new sources.

- **EPA announced <u>proposed</u> rule on 09/20/2013 and published the proposal in the Federal Register on 01/08/2014.**
  - **Clean Air Act requires EPA to take final action on proposed rule within one year of publication, by January 8, 2015.**
- **Only addresses CO2:**
  - **Limit of 1,100 lbs/MWh (gross) for new coal-fired generation.**
  - **Limit of 1,000 lbs/MWh (gross) for new gas-fired generation.**

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Major Assumptions

2. <u>Proposed or Expected New Environmental Regulations for Air and Water (Cont.)</u>

- Affects <u>new</u> units only [Coal-Fired Units, Integrated Gas Combined Cycle (IGCC)].
    - Natural Gas Fired Cane Run 7 and the future Green River 5 are the only units in the LKE fleet currently impacted.
    - Cane Run 7 NGCC emission rate estimated at 800 lbs/MWh (gross) during full load operation.
    - New simple cycle turbines only affected if at least 1/3 of maximum capacity utilized for electric generation provided to grid.

2.10 On June 2, 2014, EPA released their proposed regulations for greenhouse gas (carbon) reductions from existing fossil-fueled electric generating units (EGUs).

- Upon publication of the proposed rule in the Federal Register (FR), the EPA will have one year to issue a final rule.
- At that point, the States will have one year to develop and submit their State Implementation Plans for EPA's approval (June 2016). They can seek a one year extension for a single State Plan or a two year extension for a multiple State Plan. The EPA will then have up to one year to approve the plans.
- Interim limits on emissions from units that are in existence or began construction prior to January 8, 2014 will be based on average emissions from 2020 – 2029 with a final limit beginning 2030.

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Major Assumptions

2. <u>Proposed or Expected New Environmental Regulations for Air and Water (Cont.)</u>

- The limit is rate-based in units of lbs CO2/MW net, however, may be converted to mass-based (tons/year).
- The proposal is unclear on treatment of shutdown generation and new NGCC generation that begins construction after January 8, 2014.
- Absent further information to the contrary, Brown 1 and 2 remain active through the 10-year planning period.

2.11 The 2011 ECR compliance plan settlement and CPCN were approved December 16, 2011, and will include the following air quality controls:

- A new Mill Creek 4 WFGD (December 2014).
- A new Mill Creek 3 WFGD (June 2016).
- A new Mill Creek 1 and 2 (combined) WFGD (May 2015).
- Fabric Filters on Ghent 1-4, Mill Creek 1-4, Brown 3, and Trimble County 1.
  - o 2014 in-service: GH3 (June), GH4 (December), MC4 (December).
  - o 2015 in-service: BR3 (April), GH1 (May), GH2 (December), MC1 (May), MC2 (May), TC1 (October).
    - ✓ The existing precipitators on Brown 3 and Ghent 1 and 2 will be removed.
  - o 2016 in-service: MC3 (June).

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Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.11 Continued:

- A PAC system for Mill Creek Unit 3 and Sorbent Injection system for Mill Creek Units 3 and 4.
  - In-service October 2016.
- The Brown 1-2 Fabric Filters were removed from the 2011 ECR plan as part of the settlement. The fabric filters are not included in the 2014 BP. Brown 1 and 2 do remain in the generation mix through the planning period, however.
  - With Nalco additive included. Injection system scheduled for September 30, 2014 completion.
  - Run times may be limited.

2.12 Significant O&M and cost of sales (~$25M - $30M per year) will be incurred as remaining units become operational for MATS Compliance.

- Costs will begin ramping up in 2014 as units are completed.
  - Additional limestone usage at Mill Creek 1 and 2 WFGD.
  - Additional hydrated lime injection to protect bags at all baghouse installations.

PPL companies

Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

- Prior to 180 days after the compliance date of April 16, 2015 (or April 16, 2016 for units that have been granted an extension), all units must have completed a boiler tune-up with specific documentation of improvements and procedures and effects on CO and NO_x.
  - EPA has intent to allow for the boiler tune-up to occur prior to the compliance date.

2.13 EPA issued the Final 316(b) rule by May 19, 2014.

- **Only Mill Creek 1 will be impacted.**
  - **Two years of entrainment monitoring in 2015/2016.**
  - **State will negotiate with LG&E in 2017, with a 3-5 year implementation.**
  - **A cooling tower for Unit 1 is a sensitivity.**

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Major Assumptions

2. <u>Proposed or Expected New Environmental Regulations for Air and Water (Cont.)</u>

2.14 Effluent water guideline draft proposal was issued April 19, 2013, with the final rule targeted to be issued September, 2015.

- **Timing expected to coincide with final rules on coal combustion residuals (CCR's).**
- **A Five-Year implementation period is expected, however, a mercury discharge limit of 51 ppt for our remaining coal-fired stations as part of new KPDEs permit requirements will likely require LKE to be ahead of the EPA timeline.**
  - o **Mill Creek will likely by the first plant impacted.**
- **A four-year compliance period is expected to meet the state requirements.**
- **The estimated cost is 3X higher than the 2014 BP, largely driven by the inclusion of a limit on selenium.**
  - o **The estimate currently used is the mid-point of a level 1 engineering high and low range of eight different options that includes selenium.**

Major Assumptions

2. Proposed or Expected New Environmental Regulations for Air and Water (Cont.)

2.15 Ghent negotiated SO_3 (H_2SO_4) permitted emission limits with EPA in 2012.

- The Consent Decree was "Entered" by the Court on 8/21/2013 initiating the start of requirements accordingly.
- The Compliance Assurance Monitoring Plan was approved by the KyDAQ effective 2/4/2014.
- Additional testing will be necessary and engineering studies may be required for material changes.
- Permit will include operational monitoring of SO_3 control equipment.
- SIC Monitors will be required for each unit.
- Additional emissions testing for correlation per the Compliance Assurance Monitoring (CAM) Plan.

Major Assumptions

3. Expansion/Capacity

3.1 A combined cycle unit (Cane Run 7) will be added May 1, 2015 at the Cane Run location.

- 2 x 1, 640 MW Summer Net (Ownership is 78% KU, 22% LG&E).
- Replacing Cane Run Coal retired on that date.
- CPCN approval date of September, 2012.
- Expense profile based on a Long-Term Services Agreement being in place.

3.2 A second combined cycle unit (Green River 5) will be added May 1, 2021 at the Green River location.

- Ownership percentage will be 60% KU, and 40% LG&E.
- 2 x 1, 640 MW Summer Net, with other options for a comparable number of MW’s being considered (i.e. two 1 X 1’s).
- Expense profile based on a Long-Term Services Agreement being in place.
- Timing could move up if the municipal utilities do not end up leaving the KU system.

Major Assumptions

3. <u>Expansion/Capacity (Cont.)</u>

3.3 A 10 MW Solar Facility will be installed at the Brown Generating Station by December 31, 2016.

- Ownership percentage will be 61% KU and 39% LG&E.
- There is incremental OPEX associated with the facility.

3.4 Reserve margin purchases needed are 165 MW between May 1, 2015 and April 30, 2019.

3.5 Brown 1 and 2 are included through the planning period, but without fabric filters.

- The Nalco product, to keep mercury emissions lower, will be utilized.

3.6 The third combined cycle will not be needed until 2031, as long as Brown 1 and 2 are still active.

Major Assumptions

3. <u>Expansion/Capacity (Cont.)</u>

3.7 The five Ohio Falls units still to be rehabilitated (the other three are complete) have the following scheduled mechanical completion dates.

- Unit 1 (June, 2014).
- Unit 5 with turbine coupling repair (October, 2014).
- Unit 2 (July, 2015).
- Unit 4 (February, 2017).
- Unit 8 (May, 2016).

3.8 Black start additions (for system restoration purposes) will take place in 2017 and 2018.

- Trimble County Site 2017 in-service. Engineering takes place in 2015.
- Can Run Site 2018 in-service. Engineering takes place in 2016.

Major Assumptions

3. Expansion/Capacity (Cont.)

3.9 Group 3 retirements will be considered based on a Retire vs. Repair cost analysis if there is a failure.

- **Group 3 consists of the older, smaller CT's.**
- **No Group 3 units are being retired in the plan.**
  - **Haefling 3 was retired in 2013.**

Major Assumptions

4. <u>Coal Combustion Residuals (CCR's)</u>

4.1 EPA issued two proposals for public input for coal combustion residuals (CCR's) in June 2010.

- Final rules are expected on December 19, 2014 and once final rules are issued there will be a five-year implementation period with an additional two years to close existing ponds. Unlined ponds (and possibly even lined ponds) are expected to be eliminated for ash storage.

- EPA is looking to tie the timing of CCR's and effluent water (see 2.14) together.
    - Congress is working on a bi-partisan effort.
    - Expected timeframe of 2018 - 2020 on pond closures and 2017-2018 on construction of new process ponds.
    - CCR materials are used for closing ponds on all active coal facilities.
    - A designation of "Hazardous" vs. "Non-Hazardous" appears to be strongly trending toward "Non-Hazardous".
    - The designation will not change the capital plan but would reduce beneficial re-use opportunities for structural fill and gypsum for wallboard if declared "hazardous".

Major Assumptions

4. Coal Combustion Residuals (CCR's)

4.2 Trimble County Landfill and Transport.

- **The projected in-service date for the transport and treatment system is September, 2017.**
- **The projected in-service date for the landfill is April, 2018.**
  - **Approval of DWM permit is in January, 2015.**
  - **One year litigation of permits (1/15 – 1/16)**
  - **Construction period of 2.75 years.**

Major Assumptions

4. Coal Combustion Residuals (CCR's) (cont)

4.3 Brown Ash Pond is being converted to a landfill, with an expected in-service date of second quarter, 2016 for Phase

- **KYDWM permit expected third quarter, 2014.**
- **Construction schedule is approximately 18 months.**
- **All three phases will be staged concurrently.**

4.4 Ghent Landfill Phase 1 construction went in service in June, 2014.

- **Transport portion of the project is trending toward a September, 2014 in-service date.**

4.5 A new Mill Creek landfill will be in-service by December 31, 2019.

- **Landfill location is 1.5 miles from Mill Creek with a 1.5 mile transport pipe conveyor.**

4.6 The Cane Run MSE Wall will be completed in 4th Quarter 2014.

4.7 The Cane Run Landfill will be closed in 2016.

4.8 The Cane Run Ash pond Cap & Closure project will be completed in 2017.

4.9 All CCR Capital Projects use an annual escalation rate of 4.0%.

Major Assumptions

4. Coal Combustion Residuals (CCR's) (cont)

4.10 The pond closure projects assume that existing CCR materials from each plant can be used to fill in each pond, similar to Cane Run. If that is not allowed by rule, the estimated cost of having to instead procure top soil and clay is an additional $450M.

4.11 If CCR materials are allowed for Pond Closure, Phases II and III of the landfill projects will move further out in time relative to what is in the 10-year projections.

Major Assumptions

5. Operational and Other

5.1 Annual escalation rates for internal labor and non-labor are as follows:

- Internal labor: 3.0%.
- Non-labor 2.0%.

5.2 The next turbine overhauls by unit are as follows:

- 2014 : Mill Creek 4, Ghent 4.
- 2015 : Ghent 1, Brown 1.
- 2016 : None scheduled.
- 2017: Brown 2, Trimble 1.
- 2018: Ghent 3, Trimble 2.
- 2019: Ghent 2, Brown 3, Mill Creek 3.

Major Assumptions

5. **Operational and Other**

5.3 **Significant generator rewind/stator rewind dollars are included in the 2014-2017 timeframe.**

- **Brown 2 generator (stator and rotor) rewind in 2017 (some dollars also in 2016).**
- **Spare stator bars ordered and received for Ghent 2-4, Mill Creek 1-4, and TC 1 between 2010 – 2016.**
  - **The spare sets will be installed on MC4 in 2014, MC3 in 2019, MC2 in 2020, and MC1 in 2021.**

5.4 **The corrosion fatigue inspection schedule is as follows:**

- **2014: Ghent 4.**
- **2015: Ghent 1, Mill Creek 1.**
- **2016: Brown 1, Mill Creek 2, Mill Creek 4.**
- **2017: Brown 2, Mill Creek 1, TC1.**
- **2018: Brown 3, Ghent 1, Ghent 3, Mill Creek 4, TC2.**
- **2019: Ghent 2, Mill Creek 3.**

Major Assumptions

5. Operational and Other (cont.)

5.5 The High Energy Piping (HEP) inspection schedule is as follows:

- 2014: Ghent 3, Ghent 4, Mill Creek 4, TC2.
- 2015: Brown 1, Ghent 1, Ghent 2, Mill Creek 3.
- 2016: Brown 3, Mill Creek 2, TC2.
- 2017: Brown 2, Mill Creek 1, TC1.
- 2018: Brown 1, Ghent 1, Ghent 3, Ghent 4, Mill Creek 2, Mill Creek 3.
- 2019: Brown 2, Brown 3, Ghent 2, Mill Creek 1, Mill Creek 2, TC1.

5.6 The fuel procurement plan is pushing toward higher chlorine ILL. Basin fuels, which will drive burner modifications on at least two Mill Creek units and two Ghent units.

- Permit changes may also be needed.

Major Assumptions

5. Operational and Other (cont.)

5.7 Targets for percentage of coal hedged in the 2015 Business Plan (in the year 2015) are as follows:

Coal

- 2015 95%-100%.
- 2016 80%-90%.
- 2017 40%-90%.
- 2018 30%-70%.
- 2019 10%-50%.
- 2020 0%-30%.

  - Targets for natural gas will follow a similar progression, but will build up slowly over time and will be comparable by the year 2018.

5.8 Based on a range of $4.00 to $6.00 per MMBTU, Can Run 7 natural gas usage can range from usage of 34 million MCF at $4.00 gas, to 16 million MCF at $6.00 gas. This can change coal burn by 1.7 million tons per year.

Major Assumptions

5. Operational and Other (cont.)

5.9 Combustion turbine outages in the plan:

- Dollars are split between O&M and capital based on the estimated scope of work that is reconditioning (expense – approximately 10%) vs. new parts (capital – approximately 90%).
- The first set of hot gas path inspections for Trimble CT's are complete as of the Spring, 2013. The cycle starts again with one unit in 2016, two units in 2017, two units in 2018, and one unit in 2019.
  - Brown C inspections by unit are as follows:
    - ✓ Unit 10 in 2015.
    - ✓ Unit 6 in 2017.
    - ✓ Unit 7 in 2018.
    - ✓ Unit 11 in 2020.
    - ✓ Unit 5 in 2021.
    - ✓ Unit 8 in 2024.
    - ✓ Unit 9 in 2030.
- The expiration date for the Brown 6 and 7 Long-Term Services Agreements (LTSA) is October 1, 2016 based on the 13-year criteria.

Major Assumptions

5. Operational and Other (cont.)

- The CT component outages for Cane Run 7 are a Combustion Inspection late 2016, Hot Gas Path Inspection (HGPI) 2019, Combustion Inspection 2021, and a major in 2022 (HGPI and turbine overhaul).
  - Cane Run 7 CT's are covered under a signed LTPC.
  - The turbine/generator overhaul will be every seven years, with the first one in 2022.

5.10 CIP Version 5 will have an effective date of April 1, 2016.

5.12 Complete demolition of Paddy's Run Coal Plant will take place 2015-2016, and complete demolition of Canal Station 2016-2017. Paddy's stacks were removed in 2013.

5.13 Complete demolition of Pineville and Tyrone Power Plants will take place between 2020-2022.

Major Assumptions

5. Operational and Other (Cont.)

5.14 Expected write-offs to expense include:

- Cane Run M&S $8M (2015).
- Green River M&S $2M (2015).
- Ghent Ash Handling M&S $1M (2014).
- Mill Creek FGD M&S $1.5M (2016).

5.15 The proysm run dated August 22, 2014 is the official generation forecast for the 2015 Business Plan.

Financial Review – Prior Plan to Expectation Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OPEX (O&M and BTL):					
Prior Plan Amount	$ 700	$ 700	$ 819	$ 838	$ 858
Adjustments/Transfers:					
2015 BP Efficiency Savings	$ (48)	$ (75)	$ (176)	$ (147)	$ (150)
Current Expectation	$ 652	$ 625	$ 643	$ 691	$ 709

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Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses
($000)

Item	2013 Actual	2014 Forecast*	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M Expenses Only:							
Labor	$157	$398	$207	$209	$214	$220	$225
Non labor	$653	$394	$445	$416	$429	$471	$483
Subtotal O&M Expense	$810	$793	$652	$625	$643	$691	$709
Other Income/Expense* * (see OIE slide for detail)							
Total OPEX	$810	$793	$652	$625	$643	$691	$709

** 2014 Forecast includes the Jan - July costs of Project Development*

PPL companies

Financial Performance - OPEX

2013-2019 Other Income/Expenses (incl. BTL) ($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OIE/BTL Expenses Only:							
Labor	$ 11						
Contributions	$ -						
Employee Recognition	$ 5	$ 1					
Meals and Meetings Exp.	$ 22						
Other	$ -						
Non labor (Emp Reloc)	$ 38						
Total OIE / BTL Expense	$ 77	$ 1	$ -	$ -	$ -	$ -	$ -

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2013-2019 Capital Breakdown (w COR) – Accrual Basis ($M)

Project	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Environmental							
Brown CCR	$13	$42	$48	$21	$3	$13	$0
Cane Run CCR	$0	$0	$0	$0	$0	$0	$0
Ghent CCR	$89	$24	$18	$0	$0	$0	$1
TC CCR (Net)	$4	$4	$25	$124	$81	$65	$1
MC CCR	$0	$0	$7	$1	$39	$61	$16
Brown 3 SCR	$3	($0)	$0	$0	$0	$0	$0
Env. Air - Brown	$13	$41	$33	$0	$0	$0	$0
Env. Air - Ghent	$238	$231	$111	$4	$0	$0	$0
Env. Air - Mill Creek	$237	$329	$252	$69	$3	$0	$0
Env. Air - TC (Net)	$10	$38	$60	$2	$0	$0	$0
Env. Compliance - CCR Ruling	$0	$0	$4	$106	$77	$86	$121
Env. Compliance - Effluent Water *	$0	$1	$4	$50	$147	$264	$225
Env. Compliance - Water Intake	$0	$0	$0	$0	$6	$6	$0
New Generation Capacity							
TC2 (Net)	$1	$1	$3	$0	$0	$0	$0
Ohio Falls	$14	$11	$15	$16	$4	$0	$0
NGCC 2015 - CR7	$339	$124	$30	$0	$0	$0	$0
NGCC 2021 - GR5 *	$4	($3)	$0	$0	$3	$97	$496
Brown Solar *	$0	($0)	$10	$25	$0	$0	$0
Other							
CR & TC Black Start	$0	$0	$4	$18	$30	$18	$0
CR MSE Wall, Ash Pond & Landfill Closure	$7	$5	$5	$3	$0	$0	$0
Other	$3	$5	$7	$16	$7	$0	$0
Total Capital and Cost of Removal	$973	$852	$636	$455	$400	$609	$860

** 2014 Charges are in Preliminary Survey and are not shown in Capital in the 2015 BP RAC version*

2015-2019
Capital Reconciliation (w COR) –Accrual Basis ($M)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Prior Plan	$668	$757	$511	$434	$206
Changes:					
Brown CCR	($14)	($11)	$0	$0	$0
Cane Run CCR Closure	($2)	$0	$1	$0	$0
Ghent CCR	($15)	$0	$0	$0	$0
TC CCR (Net)	$23	($10)	($7)	($57)	$9
MC CCR	($6)	$6	($32)	($4)	$37
Ohio Falls	$1	($6)	($4)	$0	$0
NGCC 2015 - CR7	$6	$0	$0	$0	$0
NGCC 2021 - GR5 *	$85	$394	$152	($52)	($496)
Brown Solar	($10)	($25)	$0	$0	$0
Paddys Demolition	$2	($2)	$0	$0	$0
Canal Demolition	$0	($7)	$0	$6	$0
Env. Air - Brown	$10	$4	$0	$0	$0
Env. Air - Ghent	($19)	$0	$0	$0	$0
Env. Air - Mill Creek	($30)	$48	($0)	$0	$0
Env. Air - TC (Net)	($1)	$3	$0	$0	$0
Env. Compliance - CCR Ruling	$1	($56)	$56	$104	$21
Effluent Water	($3)	($43)	($49)	($167)	($225)
Water Intake	$6	$5	($6)	($6)	$0
Other	($0)	$0	$0	$0	($0)
Current Plan	$636	$455	$400	$609	$860

** Green River 5 was moved to a 2021 in-service date in 2015 BP*

Financial Performance

2013-2019 Headcount

Department	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Project Engineering	**55**	**61**	**61**	**61**	**61**	**61**	**61**
PE Coop/Intern Students	**20**	**10**	**10**	**10**	**10**	**10**	**10**
VP Transmission/Gen Serv	**2**	**2**	**2**	**2**	**2**	**2**	**2**
Business Development	**2**	**0**	**0**	**0**	**0**	**0**	**0**
TOTAL	**79**	**73**	**73**	**73**	**73**	**73**	**73**
From 2014 Business Plan		68	68	68			
Variance to 2014 Business Plan		5	5	5			

Year to Year Increases (Decreases)	2014	2015	2016	2017	2018	2019
Mechanical Engineer	1					
Electrical Engineer	1					
PE Coop/Intern Students	2					
TOTAL	**-6**	**0**	**0**	**0**	**0**	**0**

PPL companies

Plan Risks

- **Acceleration of compliance dates by EPA from assumed dates in 2014BP.**
- **Available craft labor resources.**
- **Execution of “no float” schedule on Mill Creek 3 WFGD & PJFF.**
- **Receiving permits on the landfill at Trimble County is within assumed timeframe.**
- **Performance of EPC contractors.**
- **Performance of equipment during commissioning, startup, and initial operation periods**

Appendix

PPL companies

Capital Review – Brown CCR

Accrual Basis, $Millions

Authority/ECR Comparison

	Total Projection	Current Authority	ECR Filing	Variance to Authority	Variance to ECR Filing
Aux Pond Phase II	$58	$73	$73	$15	$15
Landfill Phase I	$40	$25	$25	($15)	($15)
Main AP Closure Plan	$19			($19)	($19)
Ash & Gypsum Transport	$69	$57	$59	($12)	($10)
Landfill Phase II & III	$28	$0	$0	($28)	($28)
Total	$214	$155	$157	($40)	($38)

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP									
Aux Pond Phase II	$58	$0	$0	$0	$0	$0	$0	$0	$58
Landfill Phase I	$24	$10	$3	$0	$0	$0	$0	$0	$37
Main AP Closure Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0
Ash & Gypsum Transport	$11	$33	$29	$0	$0	$0	$0	$0	$72
Landfill Phase II & III	$0	$0	$2	$10	$3	$13	$0	$0	$28
Total 2014 BP	$92.5	$42.9	$33.8	$9.6	$3.2	$13.1	$0.0	$0.0	$195.1
2015 BP									
Aux Pond Phase II	$58	$0	$0	$0	$0	$0	$0	$0	$58
Landfill Phase I	$28	$5	$7	$0	$0	$0	$0	$0	$40
Main AP Closure Plan	$0	$1	$6	$11	$0	$0	$0	$0	$19
Ash & Gypsum Transport	$1	$36	$32	$0	$0	$0	$0	$0	$69
Landfill Phase II & III	$0	$0	$2	$10	$3	$13	$0	$0	$28
Total 2015 BP	$87	$42	$48	$21	$3	$13	$0	$0	$214
Variance to 2014 BP									
Aux Pond Phase II	($0)	$0	$0	$0	$0	$0	$0	$0	($0)
Landfill Phase I	($4)	$6	($4)	$0	$0	$0	$0	$0	($3)
Main AP Closure Plan	$0	($1)	($6)	($11)	$0	$0	$0	$0	($19)
Ash & Gypsum Transport	$10	($3)	($4)	($0)	$0	$0	$0	$0	$3
Landfill Phase II & III	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Variance to 2014 BP	$6	$1	($14)	($11)	$0	$0	$0	$0	($19)

Key Messages

- The ECR Filing for Phase I of the Landfill and the Transport system was made in June 2011.
- Phase II has been accelerated 3 years and will start contruction upon completion of Phase I.

Phase II and Phase III will be constructed consecutively as Phase II which was necessary to obtain KYDWM permit.

Capital Review – Cane Run CCR

Accrual Basis, $Millions

Authority Comparison

	Total Projection	Current Authority	Variance to Authority
Cane Run MSE Wall	$5	$5	$0
Cane Run Ash Pond and Landfill Closure	$17	$15	$2
Total	$22	$20	$2

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP									
Cane Run MSE Wall	$4	$1	$0	$0	$0	$0	$0	$0	$5
Cane Run Ash Pond and Landfill Closur	$4	$3	$3	$3	$1	$0	$0	$0	$15
Total 2014 BP	$8	$4	$3	$3	$1	$0	$0	$0	$20
2015 BP									
Cane Run MSE Wall	$3	$2	$0	$0	$0	$0	$0	$0	$5
Cane Run Ash Pond and Landfill Closur	$6	$3	$5	$3	$0	$0	$0	$0	$17
Total 2015 BP	$9	$5	$5	$3	$0	$0	$0	$0	$22
Variance to 2014 BP									
Cane Run MSE Wall	$1	($1)	$0	$0	$0	$0	$0	$0	($0)
Cane Run Ash Pond and Landfill Closur	($2)	$0	($2)	$0	$1	$0	$0	$0	($2)
Total Variance to 2014 BP	($1)	($1)	($2)	$0	$1	$0	$0	$0	($2)

Key Messages

- Change in scope from New Landfill to an MSE Wall was made in 2012.

Capital Review – Ghent CCR

Accrual Basis, $Millions

Authority/ECR Comparison

	Total Projection	Current Authority	ECR Filing	Variance to Authority	Variance to ECR Filing
Landfill Phase I/Fines & Transport	$341	$341	$205	$0	($137)
Landfill Phase II, III, Close & Cap	$135	$0	$0	($135)	($135)
Total	$476	$341	$205	($135)	($272)

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP									
Landfill Phase I	$54	$8	$2	$0	$0	$0	$1	$3	$68
Fines & Transport	$234	$20	$0	$0	$0	$0	$0	$0	$255
Landfill Phase II, III, Close & Cap	$0	$0	$0	$0	$0	$0	$0	$135	$135
Total 2014 BP	$288	$28	$2	$0	$0	$0	$1	$138	$457
2015 BP									
Landfill Phase I	$45	$3	$8	$0	$0	$0	$1	$3	$59
Fines & Transport	$251	$21	$10	$0	$0	$0	$0	$0	$282
Landfill Phase II, III, Close & Cap	$0	$0	$0	$0	$0	$0	$0	$135	$135
Total 2015 BP	$296	$24	$18	$0	$0	$0	$1	$138	$476
Variance to 2014 BP									
Landfill Phase I	$9	$5	($5)	$0	$0	$0	($0)	$0	$9
Fines & Transport	($17)	($1)	($10)	$0	$0	$0	$0	$0	($27)
Landfill Phase II, III, Close & Cap	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Variance to 2014 BP	($8)	$5	($15)	$0	$0	$0	($0)	$0	($19)

Key Messages

- The increase over the ECR Filing is due to the Transport System going from Preliminary to Level I engineering, unexpected underground interferences, excusable events with EPC, and final permit design conditions against design.

LG&E KU
PPL companies

Capital Review – Mill Creek CCR

Accrual Basis, $Millions

Authority/ECR Comparison

	Total Projection	Current Authority	ECR Filing	Variance to Authority	Variance to ECR Filing
Mill Creek Landfill Expansion	$92	$0	$0	($92)	($92)
Mill Creek CCRT - Transport	$80	$0	$0	($80)	($80)
Total	$172	$0	$0	($172)	($172)

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP									
Mill Creek Landfill Expansion	$0	$0	$1	$7	$2	$14	$19	$46	$88
Mill Creek CCRT - Transport	$0	$0	$0	$0	$5	$43	$34	$0	$82
Total 2014 BP	$0	$0	$1	$7	$7	$57	$53	$46	$171
2015 BP									
Mill Creek Landfill Expansion	$0	$0	$7	$1	$9	$19	$7	$48	$92
Mill Creek CCRT - Transport	$0	$0	$0	$0	$30	$41	$9	$0	$80
Total 2015 BP	$0	$0	$7	$1	$39	$61	$16	$48	$172
Variance to 2014 BP									
Mill Creek Landfill Expansion	$0	($0)	($6)	$6	($7)	($6)	$12	($3)	($3)
Mill Creek CCRT - Transport	$0	$0	$0	$0	($25)	$2	$25	$0	$2
Total Variance to 2014 BP	$0	($0)	($6)	$6	($32)	($4)	$37	($3)	($1)

Key Messages

- Plan includes purchase of new land, 1.5 mile pipe conveyor, new remote SFC, and utilization of existing FA and Gypsum systems.

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PPL companies

Capital Review – Trimble County CCR

Accrual Basis, $Millions

Authority/ECR Comparison

	Total Projection	Current Authority	ECR Filing	Variance to Authority	Variance to ECR Filing
BAP/GSP	$28	$30	$25	$2	($3)
Landfill Phase I/Treatment & Transpor	$322	$76	$73	($246)	($249)
Landfill Phase II, III, & IV	$180	$0	$0	($180)	($180)
Holcim	$9	$9	$8	$0	($1)
Total	$539	$115	$106	($424)	($433)

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP									
BAP/GSP	$29	$0	$0	$0	$0	$0	$0	$0	$29
Landfill Phase I	$10	$2	$19	$28	$32	$8	$10	$2	$112
Treatment & Transport	$8	$1	$29	$86	$42	$0	$0	$0	$165
Landfill Phase II, III, Close & Cap	$0	$0	$0	$0	$0	$0	$0	$148	$148
Holcim	$9	$0	$0	$0	$0	$0	$0	$0	$9
Total 2014 BP	$57	$3	$48	$113	$74	$9	$10	$150	$463
2015 BP									
BAP/GSP	$28	$0	$0	$0	$0	$0	$0	$0	$28
Landfill Phase I	$12	$3	$5	$44	$38	$42	$1	$3	$148
Treatment & Transport	$7	$0	$20	$80	$44	$23	$0	$0	$174
Landfill Phase II, III, Close & Cap	$0	$0	$0	$0	$0	$0	$0	$180	$180
Holcim	$9	$0	$0	$0	$0	$0	$0	$0	$9
Total 2015 BP	$57	$3	$25	$124	$81	$65	$1	$183	$539
Variance to 2014 BP									
BAP/GSP	$0	$0	$0	$0	$0	$0	$0	$0	$0
Landfill Phase I	($2)	($1)	$14	($16)	($5)	($34)	$9	($1)	($36)
Treatment & Transport	$1	$1	$9	$6	($2)	($23)	$0	$0	($9)
Landfill Phase II, III, Close & Cap	$0	$0	$0	$0	$0	$0	$0	($31)	($31)
Holcim	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Variance to 2014 BP	($0)	($0)	$23	($10)	($7)	($57)	$9	($32)	($75)

Key Messages

- All numbers are net of IMPA/IMEA reimbursement.
- The increase over the ECR Filing is due to refined engineering on the Transport System, permit delays, new landfill layout, and project contingencies added.
- Permitting issues have delayed Phase I at least 2 years.

PPL companies

Capital Review – Ohio Falls

Accrual Basis, $Millions

Authority Comparison

	Total Projection	Current Authority	Variance
Ohio Falls	$139	$130	($8)

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP	$95	$17	$16	$10	$0	$0	$0	$0	$138
2015 BP	$93	$11	$15	$16	$4	$0	$0	$0	$139
Variance to 2014 BP	$2	$6	$1	($6)	($4)	$0	$0	$0	($1)

Key Messages

- Above figures include removal costs of $9.7M.
- 74% of this project has been negotiated into a lump sum contract with Voith.
- Variance driven by need to rewind all generators not originally included in scope.

PPL companies

Capital Review – Cane Run 7

Accrual Basis, $Millions

Authority Comparison

	Total Projection	Current Authority	Variance
CCGT 2015 Cane Run	$563	$579	$16

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP	$387	$125	$36	$0	$0	$0	$0	$0	$549
2015 BP	$408	$124	$30	$0	$0	$0	$0	$0	$563
Variance to 2014 BP	($20)	$1	$6	$0	$0	$0	$0	$0	($14)

- The CCGT 2015 modeled on a 2 x 1, 640MW (summer, net) and assumes a 2nd quarter 2015 in-service date.
- Additional cost includes $6M for Weather Claim, $5M for Contingency, and $2.5M for Switchyard changes.

PPL companies

Capital Review – Green River 5

Accrual Basis, $Millions

Authority Comparison

	Total Projection	Current Authority	Variance
CCGT 2018	$816	$8	($809)

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP	$2	$1	$85	$394	$155	$45	$0	$0	$683
2015 BP	$4	$2	$0	$0	$3	$97	$496	$214	$816
Variance to 2014 BP	($1)	($1)	$85	$394	$152	($52)	($496)	($214)	($134)

- The CCGT 2018 is modeled after CR7 with 10% added plus 4% annual escalation

PPL companies

Capital Review – Brown Solar

Accrual Basis, $Millions

Authority Comparison

	Total Projection	Current Authority	Variance
Brown Solar	**$35**	**$3**	**$240**

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP	$0	$0	$0	$0	$0	$0	$0	$0	$0
2015 BP	$0	$0	$10	$25	$0	$0	$0	$0	$35
Variance to 2014 BP	($0)	($0)	($10)	($25)	$0	$0	$0	$0	($35)

Key Messages

- **Brown Solar was not included in the 2014 BP**
- **Costs are based on HDR's Initial Siting Study in 2014 dollars and were cash flowed into 2014 - 2016**

4% based on 2014 dollars.

PPL companies

Capital Review – Black Starts

Accrual Basis, $Millions

Authority Comparison

	Total Projection	Current Authority	Variance
Blackstart - Trimble County	$34	$0	($34)
Black Start - Cane Run	$35	$0	($35)
Total	$70	$0	($70)

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP									
Black Start - Trimble County	$0	$0	$4	$14	$16	$0	$0	$0	$34
Black Start - Cane Run	$0	$0	$0	$4	$14	$18	$0	$0	$35
Total 2014 BP	$0	$0	$4	$18	$30	$18	$0	$0	$70
2015 BP									
Black Start - Trimble County	$0	$0	$4	$14	$16	$0	$0	$0	$34
Black Start - Cane Run	$0	$0	$0	$4	$14	$18	$0	$0	$35
Total 2015 BP	$0	$0	$4	$18	$30	$18	$0	$0	$70
Variance to 2014 BP									
Black Start - Trimble County	$0	$0	$0	$0	$0	$0	$0	$0	$0
Black Start - Cane Run	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Variance to 2014 BP	$0	$0	$0	$0	$0	$0	$0	$0	$0

Key Messages

- Project Engineering took the Gen Services budget and added 5% for non-PE Labor expenses and 5% contingency.

PPL companies

Capital Review – Paddys Run & Canal Demolition

Accrual Basis, $Millions

Authority Comparison

	Total Projection	Current Authority	Variance
Paddy's Run Demolition	$17	$2	($15)
Canal Demolition	$14	$0	($14)
Total	$31	$3	($29)

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP									
Paddy's Run Demolition	$1	$1	$8	$7	$0	$0	$0	$0	$17
Canal Demolition	$0	$1	$0	$0	$7	$6	$0	$0	$13
Total 2014 BP	$1	$1	$8	$7	$7	$6	$0	$0	$30
2015 BP									
Paddy's Run Demolition	$1	$0	$7	$9	$0	$0	$0	$0	$17
Canal Demolition	$0	$0	$0	$7	$7	$0	$0	$0	$14
Total 2015 BP	$1	$1	$7	$16	$7	$0	$0	$0	$31
Variance to 2014 BP									
Paddy's Run Demolition	$0	$0	$2	($2)	$0	$0	$0	$0	($0)
Canal Demolition	$0	$0	$0	($7)	$0	$6	$0	$0	($1)
Total Variance to 2014 BP	$0	$1	$2	($9)	$0	$6	$0	$0	($1)

Key Messages

- $1.1M was spent in 2012 for the stack demolition on Paddy's Run. The remaining amounts were shifted out to 2015 through 2018.

Capital Review – Brown Air Compliance

Accrual Basis, $Millions

Authority Comparison

	Total Projection	Current Authority	Variance
Brown 3	$92	$92	$0

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP	$18	$36	$38	$0	$0	$0	$0	$0	$92
2015 BP	$18	$41	$33	$0	$0	$0	$0	$0	$92
Variance to 2014 BP	$0	($5)	$6	$0	$0	$0	$0	$0	$1

- The ECR Filing excluded removal costs of $2M.
- BR 1 & 2 Fabric Filter removed from 2014BP.

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PPL companies

Capital Review – Ghent Air Compliance

Accrual Basis, $Millions

Authority/ECR Comparison	Total Projection	Current Authority	ECR Filing	Variance to Authority	Variance to ECR Filing
Ghent 1	$180	$173	$164	($6)	($16)
Ghent 2	$146	$140	$165	($6)	$19
Ghent 3	$173	$179	$198	$6	$25
Ghent 4	$152	$158	$185	$6	$33
Total	$651	$651	$712	$0	$61

Business Plan Comparison	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP									
Ghent 1	$60	$60	$27	$0	$0	$0	$0	$0	$146
Ghent 2	$41	$35	$58	$4	$0	$0	$0	$0	$137
Ghent 3	$120	$50	$1	$0	$0	$0	$0	$0	$170
Ghent 4	$80	$58	$7	$0	$0	$0	$0	$0	$145
Total 2014 BP	$301	$202	$92	$4	$0	$0	$0	$0	$599
2015 BP									
Ghent 1	$60	$83	$37	$0	$0	$0	$0	$0	$180
Ghent 2	$39	$39	$64	$4	$0	$0	$0	$0	$146
Ghent 3	$121	$51	$1	$0	$0	$0	$0	$0	$173
Ghent 4	$85	$58	$9	$0	$0	$0	$0	$0	$152
Total 2015 BP	$305	$231	$111	$4	$0	$0	$0	$0	$651
Variance to 2014 BP									
Ghent 1	($0)	($23)	($10)	$0	$0	$0	$0	$0	($33)
Ghent 2	$2	($4)	($7)	($0)	$0	$0	$0	$0	($9)
Ghent 3	($1)	($1)	$0	$0	$0	$0	$0	$0	($2)
Ghent 4	($4)	($1)	($2)	$0	$0	$0	$0	$0	($7)
Total Variance to 2014 BP	($4)	($29)	($19)	($0)	$0	$0	$0	$0	($52)

Key Messages

- 2015 BP based on IC request and approval in May 2014.
- SCR Turn-Downs were removed in the amounts for units 1, 3 & 4.
- SAM Mitigation is not included in the amounts for all Ghent units.
- The ECR filing does not include Removal costs of $1.3M.

Capital Review – Mill Creek Air Compliance

Accrual Basis, $Millions

Authority/ECR Comparison	Total Projection	Current Authority	ECR Filing	Variance to Authority	Variance to ECR Filing
Mill Creek 1	$167	$195	$331	$28	$165
Mill Creek 2	$177	$190	$328	$13	$151
Mill Creek 3	$291	$287	$223	($4)	($68)
Mill Creek 4	$314	$270	$386	($44)	$72
Total	$948	$942	$1,268	($7)	$320

Business Plan Comparison	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP									
Mill Creek 1	$69	$60	$32	$13	$0	$0	$0	$0	$175
Mill Creek 2	$65	$54	$36	$14	$0	$0	$0	$0	$168
Mill Creek 3	$46	$35	$130	$73	$3	$0	$0	$0	$287
Mill Creek 4	$133	$98	$25	$17	$0	$0	$0	$0	$275
Total 2014 BP	$314	$248	$223	$117	$3	$0	$0	$0	$905
2015 BP									
Mill Creek 1	$66	$61	$34	$5	$0	$0	$0	$0	$167
Mill Creek 2	$47	$91	$32	$7	$0	$0	$0	$0	$177
Mill Creek 3	$48	$27	$165	$49	$1	$0	$0	$0	$291
Mill Creek 4	$141	$142	$21	$7	$1	$0	$0	$0	$314
Total 2015 BP	$302	$322	$252	$69	$3	$0	$0	$0	$948
Variance to 2014 BP									
Mill Creek 1	$3	($1)	($2)	$8	($0)	$0	$0	$0	$8
Mill Creek 2	$18	($37)	$4	$7	($0)	$0	$0	$0	($9)
Mill Creek 3	($1)	$8	($36)	$24	$2	$0	$0	$0	($4)
Mill Creek 4	($8)	($44)	$4	$10	($1)	$0	$0	$0	($39)
Total Variance to 2014 BP	$12	($74)	($30)	$48	($0)	$0	$0	$0	($44)

Key Messages

- $13M related to the MC 3 and 4 SAM are not included in the ECR filing as it was part of an earlier filing

The ECR filing does not include removal costs of $8M.

- Variance is due to actual Target Price based EPC, FGD,Equipment, and Fabric Filter EPA contracts being less than the Level I Engineering Study performed by Black & Veatch. The ECR Filing was based on that Level I Study.
- Distribution Drive included in Unit 1

LG&E KU
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Capital Review – Trimble County Air Compliance

Accrual Basis, $Millions

Authority/ECR Comparison

	Total Projection	Current Authority	ECR Filing	Variance to Authority	Variance to ECR Filing
Trimble 1	$114	$115	$124	$0	$9

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP	$15	$39	$59	$5	$0	$0	$0	$0	$118
2015 BP	$14	$38	$60	$2	$0	$0	$0	$0	$114
Variance to 2014 BP	$1	$1	($1)	$3	$0	$0	$0	$0	$4

Key Messages

- All numbers are net of IMPA/IMEA reimbursement.

Capital Review – CCR Ruling

Accrual Basis, $Millions

Authority Comparison

There is no ECR Filing or Approved Authority Amount associated with the CCR Ruling Projects.

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP	$0	$2	$5	$50	$133	$190	$142	$0	$522
2015 BP	$0	$0	$4	$106	$77	$86	$121	$130	$523
Variance to 2014 BP	$0	$2	$1	($56)	$56	$104	$21	($130)	($1)

Key Messages

- **Majority of projects remained in 2015 through 2019 in the 2014 BP due to timing and uncertainty of ruling. Costs in 2014 in the 2014 BP are mainly engineering and development of construction packages.**

PPL companies

Capital Review – Effluent Water

Accrual Basis, $Millions

Authority Comparison

There is no ECR Filing or Approved Authority Amount associated with the Effluent Water Projects.

Business Plan Comparison

	Pre-2014	2014	2015	2016	2017	2018	2019	Post 2019	Total
2014 BP	$0	$0	$1	$8	$97	$98	$0	$0	$203
2015 BP	$0	$0	$4	$50	$147	$264	$225	$285	$974
Variance to 2014 BP	$0	$0	($3)	($43)	($49)	($167)	($225)	($285)	($771)

Key Messages

- **Pre 2015 numbers are Preliminary Survey (~$3M).**
- **Amounts represent the mid-points of CH2MHill estimates.**
- **Contingency was not added to Consultant's estimates, but they are adjusted for inflation.**
- **The KPDES cost components of the ELG estimates are based on one third of the total ELG estimate plus $26M.**

PPL companies

PPL companies

Customer Services

2015 Business Plan

September 5, 2014

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LG&E KU
PPL companies

Plan Highlights

Customer focus is a core value at LG&E and KU. Customer Services strives to provide safe, reliable, and reasonable cost 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
  - Continuing Energy Efficiency programs and services for our customers
  - Maintaining operational performance levels
  - Investing in technology to enhance customer experience
  - Facility improvements based on Master Facility Plan
  - Managing "best in class" bad debt expense

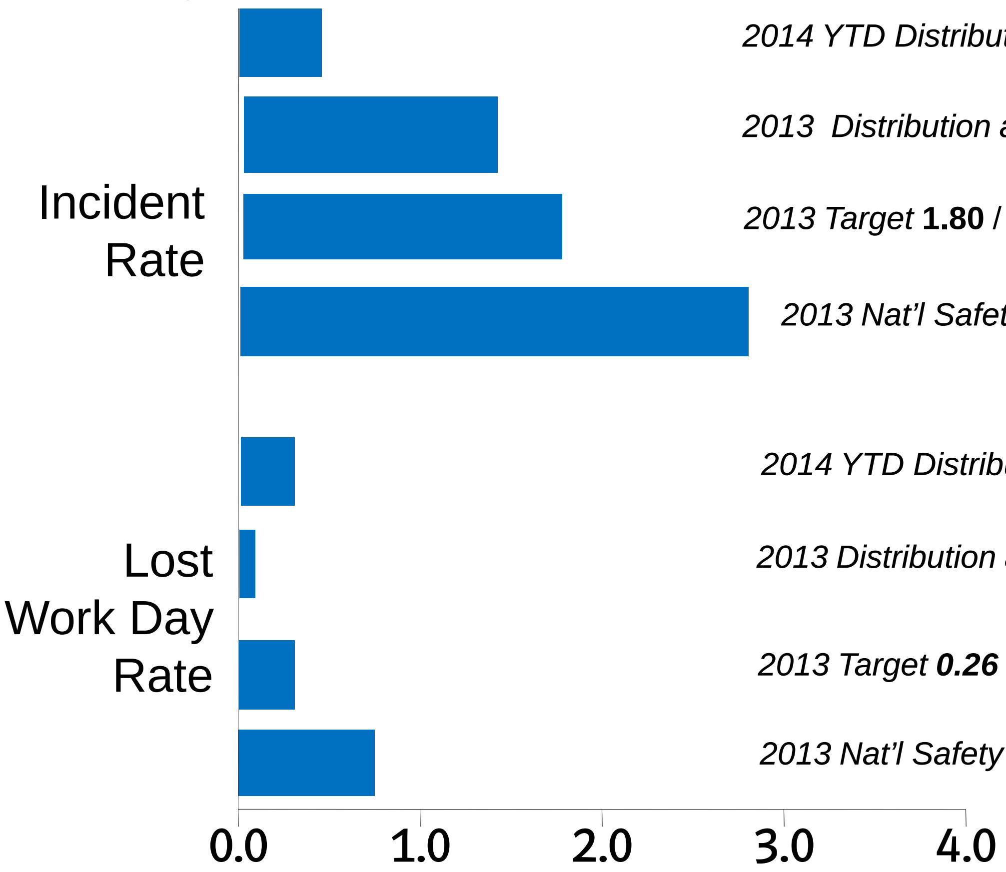
Enhance the Customer Experience — Make a connection

- Who is the customer that will be impacted?
- How will this impact the customer?
- How do I want our customer to feel when the work is done?
- What can I do to make this a positive experience for the customer?
- How does my decision fit into the rest of the customer service process?

Safety First. No Compromise!

Plan Highlights

Safety Performance



2014 YTD Distribution and Customer Service[1] *— **0.56***

*2013 Distribution and Customer Service — **1.42***

2013 Target **1.80** / 2014 Target **1.73**

2013 Nat'l Safety Council Avg. — **2.80**

2014 YTD Distribution and Customer Service[1] *— **0.23***

*2013 Distribution and Customer Service — **0.07***

*2013 Target **0.26** / 2014 Target **0.26***

*2013 Nat'l Safety Council Avg – **.80***

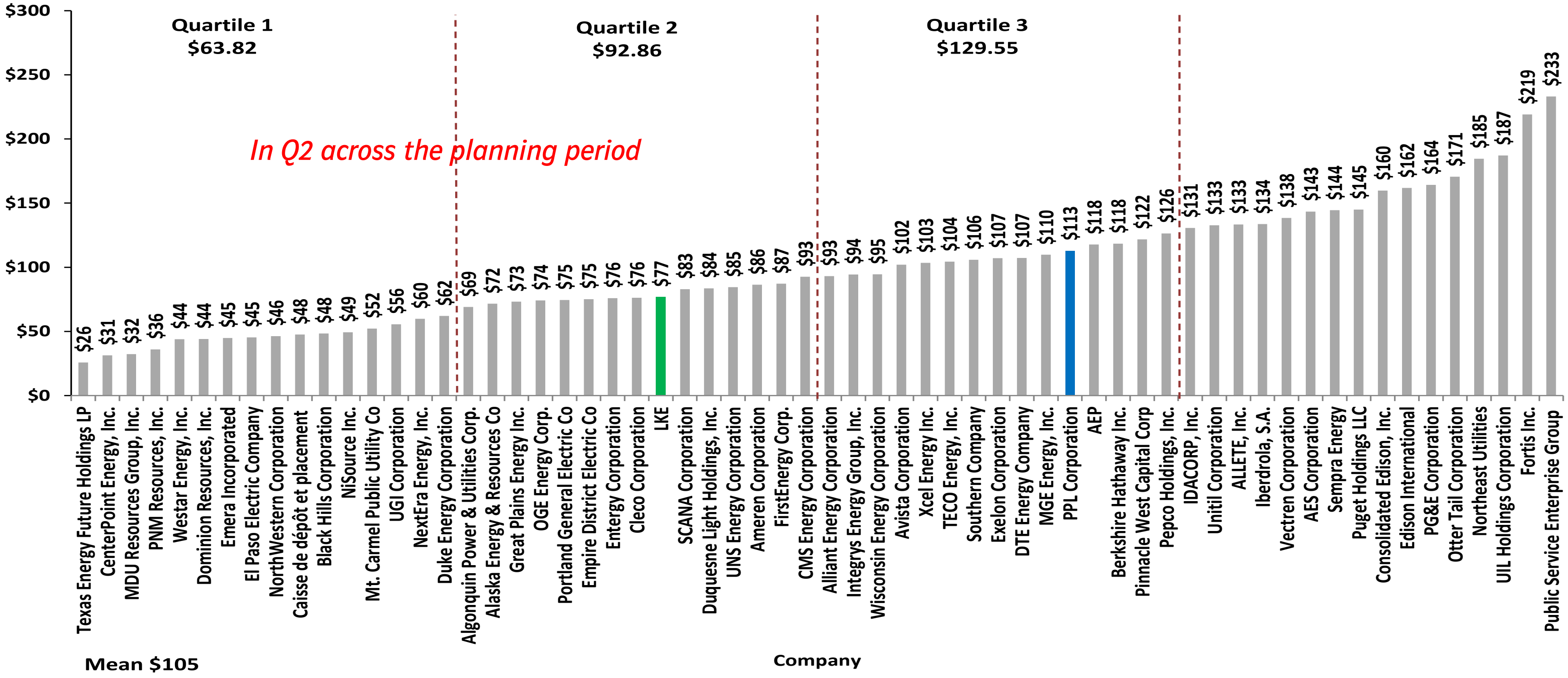
[1] As of July YTD 2014

PPL companies

Plan Highlights

Total Retail Electric O&M Cost per Customer Performance

Overall Retail Electric O&M Expenditures per Customer
FERC Utility Cost Benchmarking - 2013 Data (Electric Only)



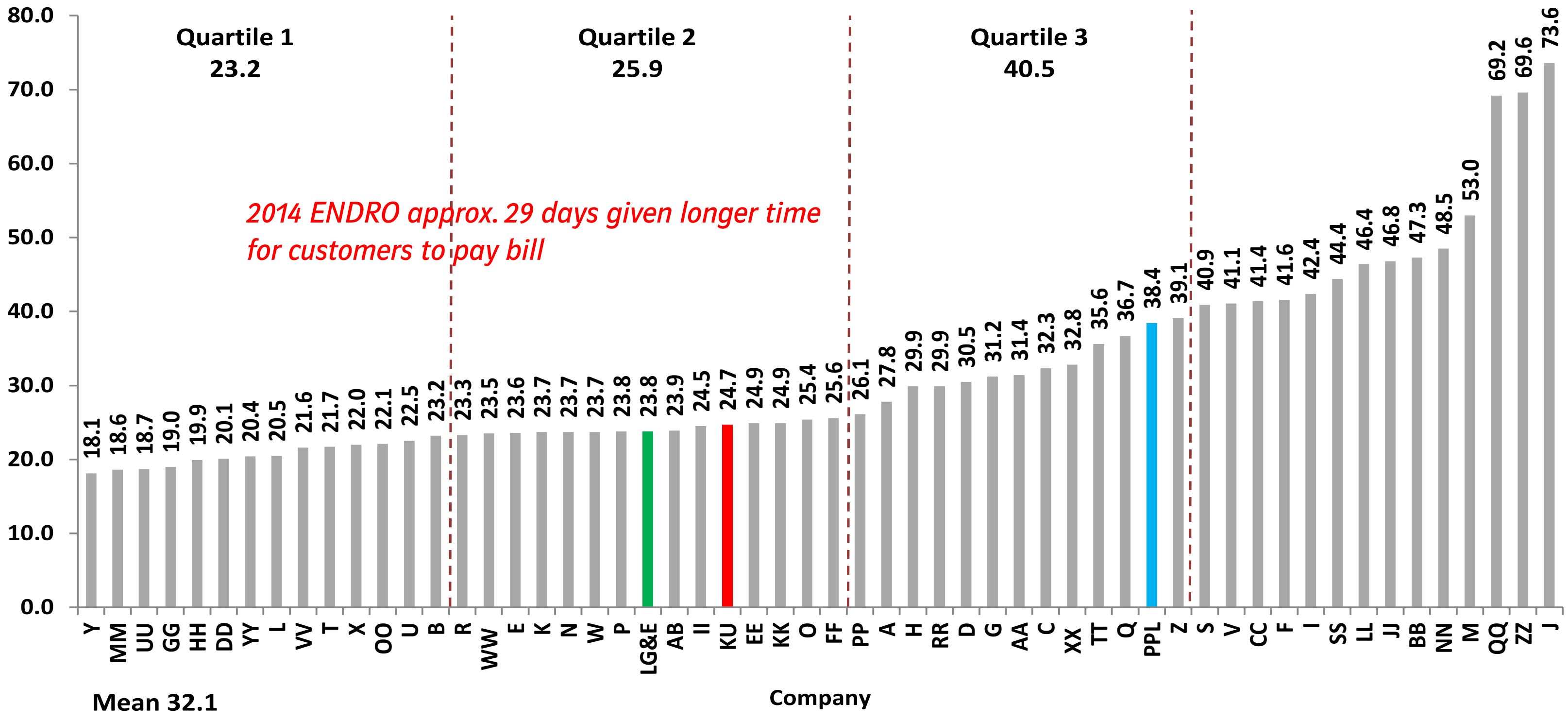
In Q2 across the planning period

LG&E KU
PPL companies

Plan Highlights

Estimated Number of Days of Revenue Outstanding (ENDRO)

ENDRO
AGA EEI DataSource - 2013 Data



2014 ENDRO approx. 29 days given longer time for customers to pay bill

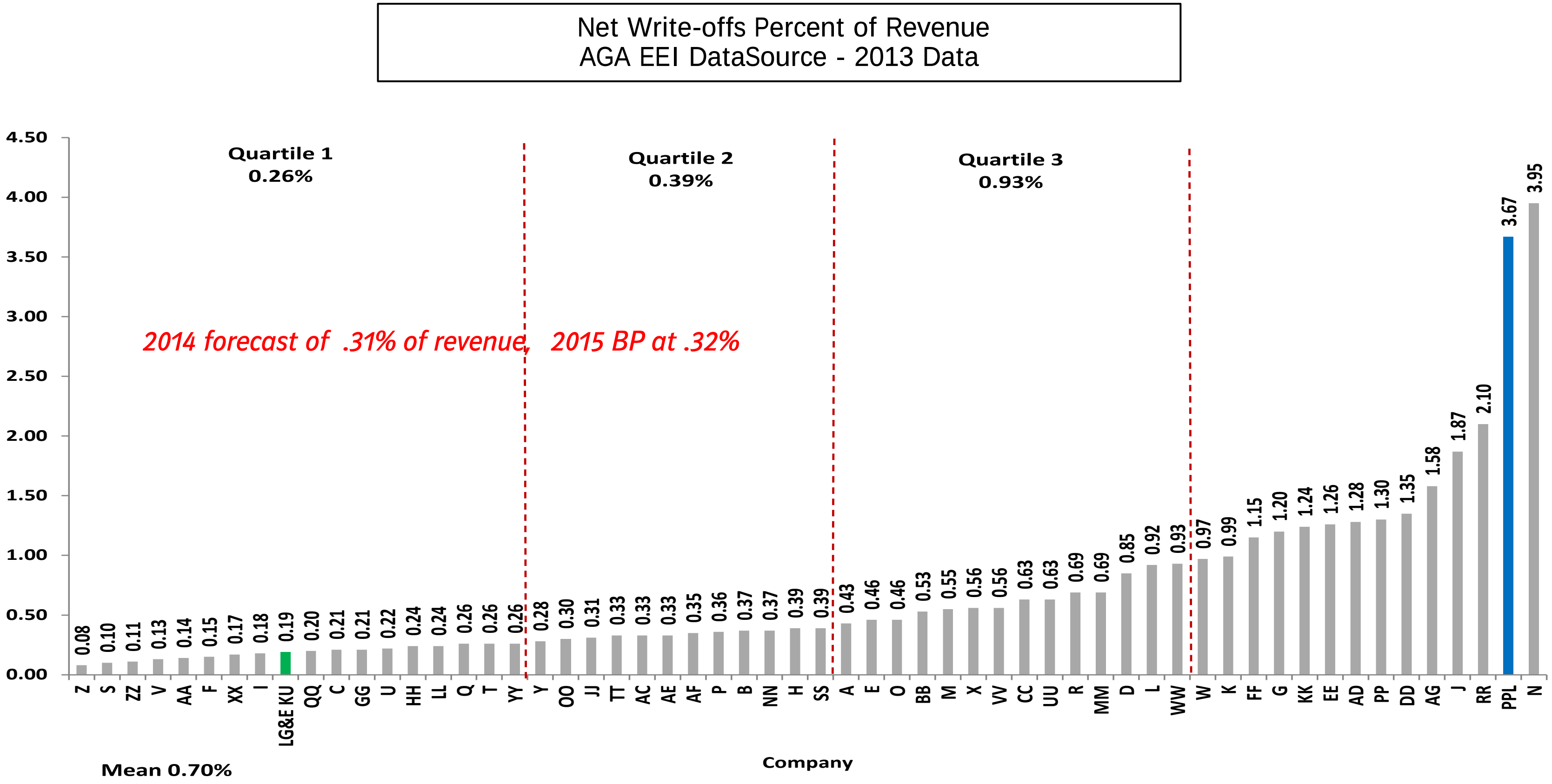
Mean 32.1

Note: January 2013 Rate Case granted customers more time to pay (minimum 22 calendar days vs. 12 calendar days).

PPL companies

Plan Highlights

Net Write-Offs as a Percent of Revenues to Ultimate Customers

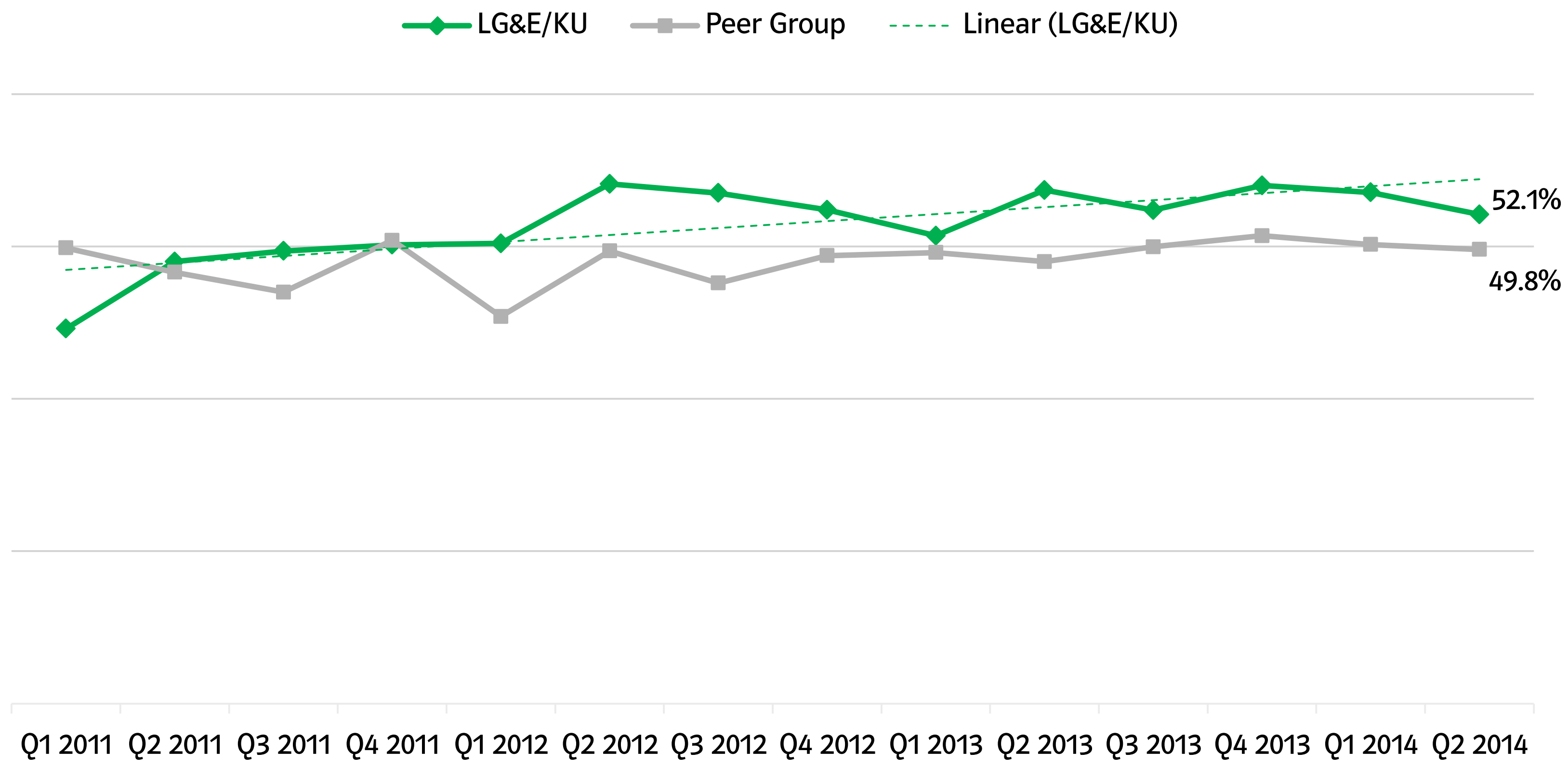


LG&E KU
PPL companies

Plan Highlights

Residential Customers – Satisfaction Survey

Measured as “Top Two Box” (score of 9 or 10 on 10-point scale)

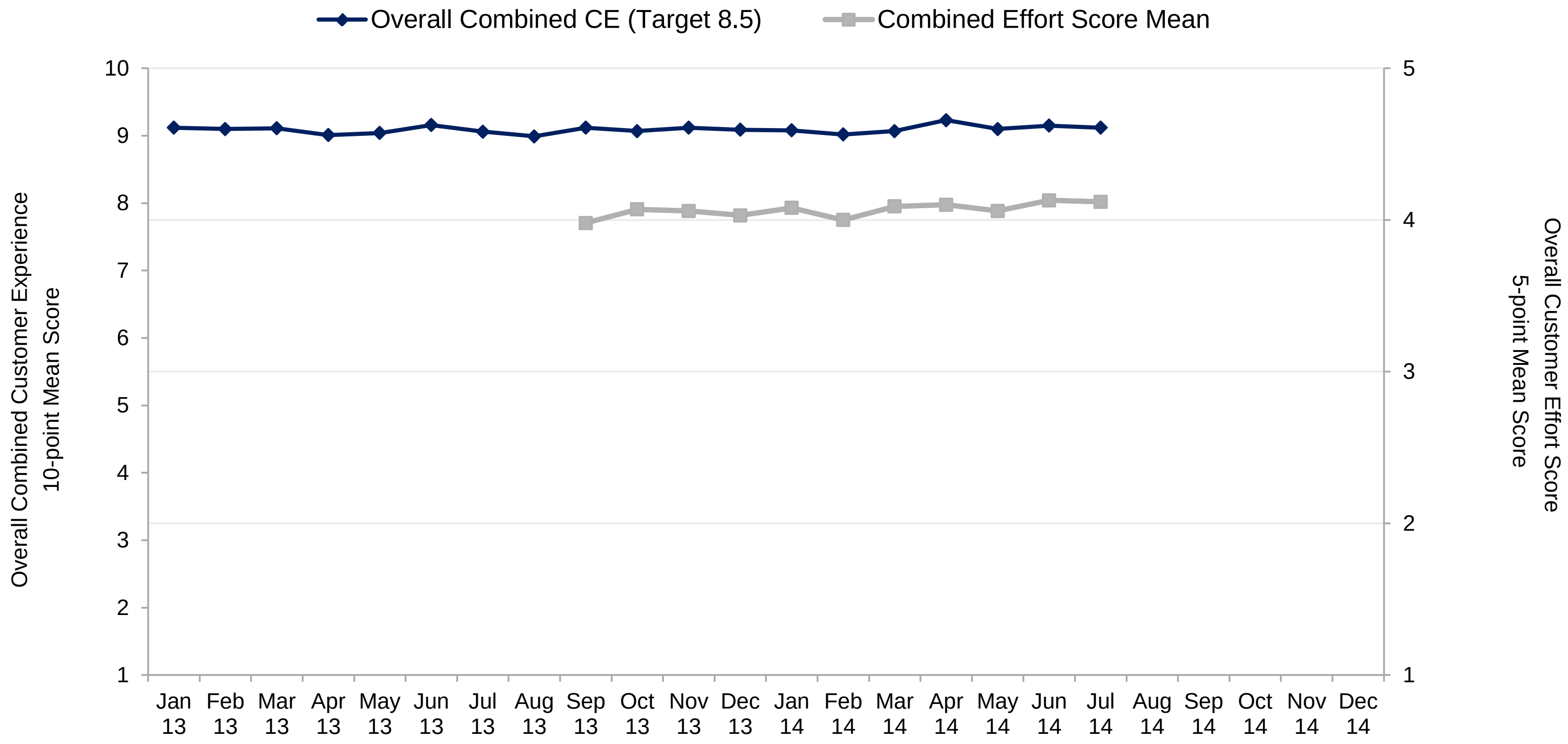


PPL companies

Plan Highlights

All Customer Contact Channels

Combined "Customer Experience" vs "Combined Effort" Score



PPL companies

Plan Highlights

- Safety and Wellness
  - *Maintain industry leading performance*
  - *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 as an aspect of safety*

Plan Highlights

- Customer Experience
  - *Advance corporate-wide "Customer Experience" strategy/initiative*
  - *Continue tracking new Customer Satisfaction Index in parallel to Top Two Box score on Company's residential satisfaction study*
  - *Continue investments in enhanced customer contact channels and the migration to a Corporate "Unified Communications" platform*
  - *Enhance our "Customer Advocacy" role through partnerships with customer focus groups*
  - *Continue commitment to corporate citizenship and community involvement*
  - *Continue to deliver the current portfolio of customer energy efficiency programs, including customer education on the need for energy efficiency*
  - *Advance our understanding of customer behavior while gaining insight into customer needs*

LG&E KU
PPL companies

Plan Highlights

- OPEX
  - — *On target in 2014 to achieve 7&5 approved forecast.*
  - — *Compounded Annual Growth Rate (CAGR) from 2014-2019 is 2.2% in total and 2.5% without bad debt.*
  - — *Major Initiatives:*
    - Customer Experience Strategy
    - Rate Case Filings
    - Right of Way Document Preservation Program
    - SAP CRM7.X Upgrade
  - — *Major Financial Risks:*
    - Customer Hardship and Uncollectible Accounts
    - Industry Regulatory Uncertainty

PPL companies

Plan Highlights

- Cost of Sales
  - *On target in 2014 to achieve 7&5 approved forecast.*
  - *Compounded Annual Growth Rate (CAGR) from 2014-2019 is (5.7%).*
  - *Major Initiatives:*
    - Energy Efficiency Continuance
- Capital
  - *On target in 2014 to achieve 7&5 approved forecast.*
  - *Compounded Annual Growth Rate (CAGR) from 2014-2019 is (6.0%) in total and (12.1%) without DSM.*
  - *Major Capital Initiatives:*
    - Energy Efficiency Programs and Services
    - Master Facility Plan Implementation
    - Gas and Electric Meters

PPL companies

Major Assumptions

- The “Customer Experience” will continue to be a significant focus across the Company.
- Customer expectations regarding levels of service and availability of information will continue to increase.
- Rate case filings during the planning period will impact customers and internal workloads.
- Bad debt expense is based on .32% of projected revenues through the planning period.
- Incremental capital costs are included for facility improvements based on the Master Facility Plan.
- With the CCS SAP CRM7.x system replacement, 25 additional positions will be needed for approximately 2-3 years. The $2.8m estimate of incremental OPEX is included in the Business Plan.

PPL companies

Major Assumptions

- Energy Efficiency projects and education will continue to be an area of focus.
- 2014 Energy Efficiency Filing for program changes starting in 2015 is successful.
- Energy Efficiency contains dollars in 2019 associated with the continuation of WeCare, DLC, Customer Education, and Admin. KPSC approval for these expenditures will be sought in 2018.
- No regulatory and legislative action to mandate smart meter / smart grid occurs during the planning period.

Financial Review – Prior Plan to Plan Expectation Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OPEX (O&M and BTL):					
Prior Plan Amount	84,750	87,292	90,931	95,353	95,411
Adjustments/Transfers:					
Security : Transfer from EDO	3,148	3,235	3,300	3,374	3,442
Safety & Tech Training : Transfer to COO	(146)	(150)	(155)	(160)	(164)
Meter Readers : Delay to Apr 2016	(328)	(84)	-	-	-
HVAC Costs (Offset in Clearing)	225	225	225	225	225
Business Offices : Transfer to CFO	(55)	(56)	(57)	(58)	(59)
Plan Adjustment	(2,137)	(2,400)	(2,625)	(2,698)	(2,698)
Current Plan Expectation	85,457	88,062	91,619	96,036	96,157
GM EXP (OCOS):					
Prior Plan Amount	37,245	38,629	40,411	42,260	42,260
Adjustments/Transfers:					
Current Plan Expectation	37,245	38,629	40,411	42,260	42,260

Financial Performance - OPEX

2013-2019 O&M and Other Income/Expenses
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
O&M Expenses Only:							
Labor	**36,343**	**38,722**	**39,978**	**41,869**	**43,282**	**44,581**	**45,918**
Non-Labor							
Bad Debt Expense	5,243	12,000	10,100	10,500	11,200	11,700	12,100
Outside Services	23,851	24,342	24,825	24,953	26,909	25,585	26,075
Materials	2,322	2,095	2,372	2,457	2,532	2,582	2,634
Transportation	1,807	1,841	1,513	1,705	1,742	1,777	1,812
Postage	5,030	5,221	5,353	5,679	5,898	6,016	6,136
Other Non-Labor [1]	7,058	2,993	2,577	2,620	2,621	2,720	2,895
Total Non-Labor	**45,311**	**48,492**	**46,740**	**47,914**	**50,902**	**50,380**	**51,652**
Subtotal O&M Expense	**81,654**	**87,214**	**86,718**	**89,783**	**94,184**	**94,961**	**97,570**
Other Income/Expense* * (see OIE slide for detail)	2,752	2,772	2,404	2,465	2,523	2,573	2,624
Total OPEX	**84,406**	**89,986**	**89,122**	**92,248**	**96,707**	**97,534**	**100,194**

[1] 2013 includes costs for the LG&E Center, KU General Office, Simpsonville & Morganfield, which were transferred to clearing in 2014.

LG&E KU
PPL companies

Financial Performance - OPEX

2013-2019 Other Income/Expenses (incl. BTL)
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
OIE / BTL Expenses Only :							
Labor	51	100	123	127	130	134	138
Contributions	2,078	2,273	1,817	1,867	1,902	1,940	1,979
Employee Recognition	343	363	374	384	390	396	402
Meals and Meetings Exp.	149	16	2	2	2	2	2
Other	131	20	88	85	99	101	103
Total OIE / BTL Expense	2,752	2,772	2,404	2,465	2,523	2,573	2,624

PPL companies

2015-2019 O&M / Other Expense Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Plan Expectation	85,457	88,062	91,619	96,036	96,157
Drivers:					
Bad Debt Expense	2,397	2,418	2,153	301	2,950
CCS	-	774	2,073	-	-
Gas Meter Reclass from Capital	554	569	580	592	605
Work-Force Plan Impacts	(217)	153	203	216	226
Contract Administration : Xerox	40	198	245	296	337
Revenue Assurance Services	120	85	119	122	124
Customer Communication & Notifications	187	187	164	167	171
Transmission System Impact Studies	99	104	96	81	83
Budget Stretch	-	(395)	(370)	-	-
Other	485	93	(175)	(277)	(459)
Current Plan	89,122	92,248	96,707	97,534	100,194

Increases / (Decreases)

Financial Performance

2013-2019 Margin Expenses / Cost of Sales
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Margin Expenses							
Mechanism Recoverable:							
DSM Costs	34,348	35,875	36,665	38,410	40,390	42,355	26,906
Bad Debt Related to GSC	155	244	-	-	-	-	-
Total Margin/Cost of Sales	34,503	36,119	36,665	38,410	40,390	42,355	26,906

LG&E KU
PPL companies

2015-2019 Margin/Cost of Sales Reconciliation ($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Mechanism recoverable					
Prior Plan / Plan Expectation	37,245	38,629	40,411	42,260	42,260
Drivers					
Customer Engagement & Programs	(580)	(219)	(21)	95	(15,354)
Current Plan	36,665	38,410	40,390	42,355	26,906

LG&E KU
PPL companies

2013-2019 Capital Breakdown (w COR) – Accrual Basis ($000)

Project	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Retail							
DSM	3,339	2,418	3,093	3,580	5,620	3,659	5,269
Other	99	1,332	375	375	385	385	385
Total Retail	3,438	3,750	3,468	3,955	6,005	4,044	5,654
Metering							
Meter Purchases	4,490	4,960	4,778	4,920	5,068	5,221	5,377
Other	183	557	547	335	335	335	335
Total Metering	4,673	5,517	5,325	5,255	5,403	5,556	5,712
Operating Services							
Tenant Improvements (LG&E Center)	2,957	1,840	1,845	1,845	-	-	-
Furniture & Equipment (LG&E Center)	533	1,097	1,074	1,020	1,025	-	-
Regional Operating Facilities Consolidations	-	-	500	5,386	500	5,529	500
Facility Improvements	1,580	4,400	3,636	330	2,375	347	1,151
Other	1,298	2,326	1,628	1,259	882	895	908
Total Operating Services	6,368	9,663	8,683	9,840	4,782	6,771	2,559
Total Capital and Cost of Removal	14,479	18,930	17,476	19,050	16,190	16,371	13,925

PPL companies

2015-2019
Capital Reconciliation (w COR) – Accrual Basis
($000)

	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Prior Plan	**23,610**	**13,178**	**16,050**	**9,644**	**N / A**
Changes:					
DSM : Demand Load Control	971	1,776	1,821	1,887	
DSM : Smart-Grid Technology	(2,188)	-	2,000	-	
Regional Operating Facilities Consolidations	(5,386)	5,386	(5,529)	5,529	
Property for Facilities Consolidations	500		500		
Facility Improvements	157	(362)	1,681	(347)	
Wellness Center	32	(706)	-	-	
Other	(220)	(222)	(333)	(342)	
Total Changes : Incr / (Decr)	**(6,134)**	**5,872**	**140**	**6,727**	
Current Plan	**17,476**	**19,050**	**16,190**	**16,371**	**13,925**

LG&E KU
PPL companies

Financial Performance

2013-2019 Headcount

Department	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
VP, Customer Services	2	2	2	2	2	2	2
Operating Services & Business Process Management	37	39	43	48	48	48	48
Revenue Collection & Metering [1]	207	214	215	226	226	226	226
Customer Service & Marketing	369	389	394	394	394	394	394
Energy Efficiency	22	20	25	25	25	25	25
Corporate Security & Business Continuity	8	9	10	10	10	10	10
Interns	1	4	1	1	1	1	1
TOTAL	**646**	**677**	**690**	**706**	**706**	**706**	**706**
From 2014 Business Plan		688	710	712			
Variance to 2014 Business Plan		-11	-20	-6			

Year to Year Increases (Decreases)	2014	2015	2016	2017	2018	2019
1.) Maintenance / Operational	27	16	16			
2.) Compliance – NERC, FERC, CIP, etc.	1					
3.) EPA / Environmental						
4.) Administrative / Corporate	3	-3				
TOTAL	**31**	**13**	**16**	**0**	**0**	**0**
Contractor Offsets By Year: (New hire reducing contractor use)	1	2	13	0	0	0

[1] 2016 includes 11 meter readers from Green River

PPL companies

Operational Performance

Key Performance Indicators

KPI	2013 Year End	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Overall Customer Experience	9.08	8.50	8.50	8.50	8.50	8.50	8.50
Overall Customer Satisfaction (TIA Points)	21.00	18.00	18.00	18.00	18.00	18.00	18.00
Safety - Employees Incident Rate	1.42	1.73	1.70	1.70	1.70	1.70	1.70
Safety - Contractors Incident Rate	1.11	2.00	1.90	1.90	1.90	1.90	1.90
O&M Cost Per Customer - Retail Electric	76.88	85.90	85.99	88.36	91.83	94.76	81.62

Plan Risks

- Increased Capital and O&M Costs due to Industry Regulatory Actions
- Customer Hardship and Uncollectible Accounts
- Fuel Prices
- Future Energy Efficiency Regulatory Approvals
- Customer Satisfaction Impacts Due to Ongoing Rate Case Filings
- Future Regulatory or Legislative Smart Meter/Grid Requirements

Appendix

PPL companies

2013-2019
Year over Year Walk Forward
OPEX and Other Expense

2013 Actual	**84,406**
Labor Changes	2,428
Bad Debt Expense	6,757
Contributions	194
Operating Services Clearing	(6,997)
Field Services & Meter Reading Outside Services	889
Gas Meters Reclass from Capital	342
Settlement	500
Other Non-Labor (Incl. 2% Inflation)	1,467
2014 FC	**89,986**
Labor Changes	1,279
Bad Debt Expense	(1,900)
Contributions	(456)
Settlement	(500)
Other Non-Labor	713
2015 Budget	**89,122**
Labor Changes	1,895
Bad Debt Expense	400
CCS Project	774
Budget Stretch	(395)
Other Non-Labor	452
2016 Plan	**92,248**

2016 Plan	**92,248**
Labor Changes	1,416
Bad Debt Expense	700
CCS Project	1,299
Budget Stretch	25
Other Non-Labor	1,019
2017 Plan	**96,707**
Labor Changes	1,302
Bad Debt Expense	500
CCS Project	(2,073)
Budget Stretch	370
Other Non-Labor	728
2018 Plan	**97,534**
Labor Changes	1,341
Bad Debt Expense	400
Other Non-Labor	919
2019 Plan	**100,194**

Increases / (Decreases)

PPL companies

2013-2019
Year over Year Walk Forward
GMEXP / Cost of Sales

2013 Actual	34,503
Additional Programs & Greater Customer Engagement	1,616
2014 FC	36,119
Additional Programs & Greater Customer Engagement	546
2015 Budget	36,665
Additional Programs & Greater Customer Engagement	1,745
2016 Plan	38,410
Additional Programs & Greater Customer Engagement	1,980
2017 Plan	40,390
Additional Programs & Greater Customer Engagement	1,965
2018 Plan	42,355
End of various programs in 2018.	(15,449)
2019 Plan	26,906

Increases / (Decreases)

LG&E KU
PPL companies

2014-2019
Headcount Progression

July 2014 Headcount	**665**
Revenue Collection & Metering	3
Customer Services & Marketing	8
Corporate Security & Business Continuity	1
2014 Headcount FC	**677**
Operating Services & Business Process Mgmt	4
Revenue Collection & Metering	1
Customer Services & Marketing	5
Energy Efficiency	5
Corporate Security & Business Continuity	1
Interns	-3
2015 Headcount Budget	**690**

2015 Headcount Budget	**690**
Operating Services & Business Process Mgmt	5
Revenue Collection & Metering [1]	11
2016 Headcount Plan	**706**
2017 Headcount Plan	**706**
2018 Headcount Plan	**706**
2019 Headcount Plan	**706**

(Decreases) / Increases

[1] Meter Readers from Green River

LG&E KU
PPL companies

Headcount & Employee Expense

2014-2019 Headcount

Business Unit Name	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Total Full Time & Part Time Headcount (without interns)	673	689	705	705	705	705

Employee Related Expenses ($000s)	2014	2015	2016	2017	2018	2019
1.) Training & Development	$290	$281	$288	$316	$322	$329
2.) Travel	$267	$246	$291	$299	$305	$312
3.) Meals and Expenses	$547	$578	$554	$567	$579	$590
4.) Employee Recognition	$363	$374	$384	$390	$396	$402
5.) Employee Dues & Memberships	$3	$5	$6	$3	$3	$3
TOTAL	**$1,470**	**$1,484**	**$1,523**	**$1,575**	**$1,605**	**$1,636**
Average Employee Expense per Number of Employees	**$2**	**$2**	**$2**	**$2**	**$2**	**$2**

PPL companies

2013-2019
Other Balance Sheet Costs
($000)

Item	2013 Actual	2014 Forecast	2015 Budget	2016 Plan	2017 Plan	2018 Plan	2019 Plan
Operating Services Clearing							
Labor	11						
Non labor	3,206	10,234	10,016	9,950	10,086	10,232	10,398
Total	**3,217**	**10,234**	**10,016**	**9,950**	**10,086**	**10,232**	**10,398**
Total Other Costs	**3,217**	**10,234**	**10,016**	**9,950**	**10,086**	**10,232**	**10,398**

2013 costs for the LG&E Center, KU General Office, Simpsonville & Morganfield were in O&M and were transferred to clearing in 2014.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(d)
Sponsoring Witness: Kent W. Blake

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 increase in rates sought in this case.

2013 Budget - Louisville Gas and Electric Company

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Electric Operating Revenues	97,067,781	88,386,232	84,908,261	80,779,096	89,347,778	105,361,564	118,751,115	119,903,369	101,685,427	83,807,834	86,188,691	97,099,885	1,153,287,032
Gas Operating Revenues	51,908,972	46,255,311	34,756,176	19,887,284	15,308,373	12,074,264	11,906,960	12,259,714	12,861,232	18,042,259	29,924,915	49,851,159	315,036,620
Total Operating Revenues	148,976,753	134,641,543	119,664,437	100,666,380	104,656,151	117,435,828	130,658,075	132,163,083	114,546,659	101,850,093	116,113,607	146,951,043	1,468,323,652
Operating Expenses													
Fuel for Electric Generation	36,824,022	33,097,768	28,841,811	29,119,134	31,902,201	37,080,555	41,584,588	41,886,826	33,882,849	27,151,957	31,936,141	35,530,669	408,838,521
Power Purchased	3,556,880	3,405,934	4,315,910	2,952,610	3,187,438	3,416,717	3,872,873	4,099,692	3,069,807	4,017,935	3,181,234	3,643,360	42,720,390
Gas Supply Expenses	28,981,231	25,975,326	18,205,016	8,472,078	5,382,768	2,952,299	2,736,870	2,795,813	3,078,833	6,472,079	14,724,390	28,282,465	148,059,168
Other Operation Expenses	22,400,796	20,312,489	21,586,962	21,535,872	22,207,649	22,140,422	23,160,106	24,217,843	24,412,306	23,124,604	21,465,062	23,521,675	270,085,786
Maintenance	7,686,789	7,785,543	11,356,153	12,419,629	12,330,706	8,690,407	8,812,805	9,672,394	10,295,278	10,677,933	10,012,032	8,228,677	117,968,346
Depreciation & Amortization Expense	12,387,972	12,406,368	12,432,004	12,460,367	12,489,659	12,534,300	12,578,518	12,654,459	12,723,886	12,760,512	12,809,937	12,950,823	151,188,805
Current Income Taxes	11,820,450	9,469,828	6,258,010	2,812,935	4,144,530	9,153,400	11,893,845	11,652,287	7,701,649	4,295,150	5,480,457	10,738,000	95,420,543
Property and Other Taxes	2,740,728	2,740,728	2,740,728	2,740,728	2,740,728	2,740,728	2,744,450	2,744,450	2,744,450	2,744,450	2,744,450	2,744,449	32,911,067
Amortization of Investment Tax Credit	(211,667)	(211,667)	(211,667)	(211,667)	(211,667)	(211,667)	(211,667)	(211,667)	(211,667)	(211,667)	(211,667)	(211,667)	(2,540,000)
Total Operating Expenses	126,187,202	114,982,318	105,524,927	92,301,686	94,174,013	98,497,162	107,172,389	109,512,098	97,697,391	91,032,954	102,142,036	125,428,451	1,264,652,626
Net Operating Income	22,789,551	19,659,226	14,139,510	8,364,694	10,482,138	18,938,666	23,485,686	22,650,985	16,849,267	10,817,139	13,971,570	21,522,592	203,671,026
Other Income less deductions	(168,840)	(169,618)	(141,291)	(145,050)	(230,572)	(121,130)	(106,781)	(86,692)	(62,142)	(98,732)	(88,547)	(98,699)	(1,518,095)
Income before Interest Charges	22,620,711	19,489,607	13,998,219	8,219,644	10,251,566	18,817,536	23,378,905	22,564,294	16,787,125	10,718,408	13,883,023	21,423,894	202,152,932
Interest Charges	3,390,774	3,391,913	3,387,856	3,393,372	3,411,166	3,427,977	3,437,995	3,449,165	3,462,113	3,475,340	4,498,087	4,358,902	43,084,660
Net Income	19,229,937	16,097,694	10,610,363	4,826,272	6,840,400	15,389,559	19,940,910	19,115,129	13,325,012	7,243,068	9,384,936	17,064,992	159,068,272

2013 Budget - Louisville Gas and Electric Company - Total Electric

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Electric Operating Revenues	97,067,781	88,386,232	84,908,261	80,779,096	89,347,778	105,361,564	118,751,115	119,903,369	101,685,427	83,807,834	86,188,691	97,099,885	1,153,287,032
Total Operating Revenues	97,067,781	88,386,232	84,908,261	80,779,096	89,347,778	105,361,564	118,751,115	119,903,369	101,685,427	83,807,834	86,188,691	97,099,885	1,153,287,032
Operating Expenses													
Fuel for Electric Generation	36,824,022	33,097,768	28,841,811	29,119,134	31,902,201	37,080,555	41,584,588	41,886,826	33,882,849	27,151,957	31,936,141	35,530,669	408,838,521
Power Purchased	3,556,880	3,405,934	4,315,910	2,952,610	3,187,438	3,416,717	3,872,873	4,099,692	3,069,807	4,017,935	3,181,234	3,643,360	42,720,390
Other Operation Expenses	17,705,240	16,042,905	16,895,548	16,403,825	17,062,153	17,119,162	17,818,412	18,580,289	18,688,671	17,512,142	16,351,591	18,272,002	208,451,940
Maintenance	6,461,619	6,616,331	10,121,855	11,110,799	10,730,342	7,232,658	7,435,703	8,280,938	8,590,957	9,293,515	8,721,597	7,068,592	101,664,906
Depreciation & Amortization Expense	9,910,378	9,925,094	9,945,603	9,968,294	9,991,727	10,027,440	10,062,814	10,123,567	10,179,109	10,208,410	10,247,950	10,360,658	120,951,044
Current Income Taxes	11,070,868	7,590,065	5,006,408	2,622,497	3,900,915	7,322,720	10,057,963	10,661,075	6,161,319	3,994,240	4,642,913	8,590,400	81,621,384
Property and Other Taxes	2,192,582	2,192,582	2,192,582	2,192,582	2,192,582	2,192,582	2,195,560	2,195,560	2,195,560	2,195,560	2,195,560	2,195,559	26,328,854
Amortization of Investment Tax Credit	(201,083)	(201,083)	(201,083)	(201,083)	(201,083)	(201,083)	(201,083)	(201,083)	(201,083)	(201,083)	(201,083)	(201,083)	(2,413,000)
Total Operating Expenses	87,520,506	78,669,597	77,118,634	74,168,658	78,766,276	84,190,751	92,826,830	95,626,864	82,567,189	74,172,675	77,075,902	85,460,157	988,164,039
Net Operating Income - Electric	9,547,275	9,716,635	7,789,627	6,610,438	10,581,502	21,170,812	25,924,285	24,276,505	19,118,238	9,635,159	9,112,789	11,639,728	165,122,993
Other Income less deductions	(135,072)	(135,695)	(113,033)	(116,040)	(184,458)	(96,904)	(85,425)	(69,353)	(49,714)	(78,985)	(70,838)	(78,959)	(1,214,476)
Interest Charges	2,712,619	2,713,530	2,710,285	2,714,698	2,728,933	2,742,382	2,750,396	2,759,332	2,769,690	2,780,272	3,598,470	3,487,122	34,467,728
Net Income - Electric	6,699,583	6,867,410	4,966,309	3,779,701	7,668,111	18,331,527	23,088,464	21,447,820	16,298,834	6,775,901	5,443,482	8,073,647	129,440,789

2013 Budget - Louisville Gas and Electric Company - Total Gas

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Gas Operating Revenues	51,908,972.28	46,255,311.31	34,756,176.29	19,887,284.38	15,308,373.36	12,074,264.04	11,906,960.04	12,259,713.72	12,861,232.08	18,042,258.87	29,924,915.46	49,851,158.59	315,036,620
Total Operating Revenues	51,908,972	46,255,311	34,756,176	19,887,284	15,308,373	12,074,264	11,906,960	12,259,714	12,861,232	18,042,259	29,924,915	49,851,159	315,036,620
Operating Expenses													
Gas Supply Expenses	28,981,231	25,975,326	18,205,016	8,472,078	5,382,768	2,952,299	2,736,870	2,795,813	3,078,833	6,472,079	14,724,390	28,282,465	148,059,168
Other Operation Expenses	4,695,556	4,269,584	4,691,414	5,132,047	5,145,496	5,021,260	5,341,694	5,637,554	5,723,635	5,612,462	5,113,471	5,249,673	61,633,846
Maintenance	1,225,170	1,169,212	1,234,298	1,308,830	1,600,364	1,457,749	1,377,102	1,391,456	1,704,321	1,384,418	1,290,435	1,160,085	16,303,440
Depreciation & Amortization Expense	2,477,594	2,481,274	2,486,401	2,492,073	2,497,932	2,506,860	2,515,704	2,530,892	2,544,777	2,552,102	2,561,987	2,590,165	30,237,761
Current Income Taxes	749,582	1,879,763	1,251,602	190,438	243,615	1,830,680	1,835,883	991,212	1,540,330	300,910	837,544	2,147,600	13,799,159
Property and Other Taxes	548,146	548,146	548,146	548,146	548,146	548,146	548,890	548,890	548,890	548,890	548,890	548,890	6,582,213
Amortization of Investment Tax Credit	(10,583)	(10,583)	(10,583)	(10,583)	(10,583)	(10,583)	(10,583)	(10,583)	(10,583)	(10,583)	(10,583)	(10,583)	(127,000)
Total Gas Operating Expenses	38,666,696	36,312,721	28,406,293	18,133,028	15,407,737	14,306,410	14,345,559	13,885,234	15,130,203	16,860,278	25,066,135	39,968,294	276,488,587
Net Operating Income - Gas	13,242,277	9,942,591	6,349,883	1,754,256	(99,364)	(2,232,146)	(2,438,599)	(1,625,520)	(2,268,971)	1,181,980	4,858,781	9,882,865	38,548,033
Other Income less deductions	(33,768)	(33,924)	(28,258)	(29,010)	(46,114)	(24,226)	(21,356)	(17,338)	(12,428)	(19,746)	(17,709)	(19,740)	(303,619)
Interest Charges	678,155	678,383	677,571	678,674	682,233	685,595	687,599	689,833	692,423	695,068	899,617	871,780	8,616,932
Net Income - Gas	12,530,354	9,230,284	5,644,054	1,046,572	(827,711)	(2,941,968)	(3,147,554)	(2,332,691)	(2,973,822)	467,166	3,941,454	8,991,344	29,627,483

2014 Budget - Louisville Gas and Electric Company - Total Company

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Electric Operating Revenues	96,680,418	91,859,691	91,142,955	83,519,403	92,689,957	106,443,959	116,952,321	117,680,101	100,126,444	85,524,299	85,036,223	95,336,279	1,162,992,050
Gas Operating Revenues	53,779,593	46,962,864	34,197,979	19,557,693	14,952,263	11,852,705	11,206,115	11,503,813	12,030,906	17,630,429	30,101,268	49,156,598	312,932,225
Total Operating Revenues	150,460,010	138,822,555	125,340,934	103,077,097	107,642,220	118,296,664	128,158,436	129,183,914	112,157,350	103,154,728	115,137,490	144,492,877	1,475,924,275
Operating Expenses													
Fuel for Electric Generation	36,872,763	36,521,915	35,252,961	30,507,924	33,723,489	36,852,738	41,236,510	41,676,007	34,148,875	28,916,129	29,773,246	34,718,999	420,201,557
Power Purchased	3,797,848	3,278,775	3,773,739	3,430,798	3,885,191	3,706,808	3,819,066	3,965,259	3,350,612	3,922,459	3,558,781	3,492,233	43,981,568
Gas Supply Expenses	31,446,711	27,152,403	18,690,946	9,061,630	5,895,573	3,310,642	3,034,743	3,096,995	3,548,918	7,136,463	15,793,927	28,899,207	157,068,158
Other Operation Expenses	22,186,451	20,704,064	21,159,854	20,812,564	22,252,671	24,557,594	23,291,440	23,679,423	23,552,859	22,572,794	20,735,504	22,707,201	268,212,419
Maintenance	7,615,695	8,103,487	10,327,485	12,075,347	10,394,055	9,344,762	9,301,398	8,628,631	9,568,210	12,628,672	11,472,289	8,881,459	118,341,490
Depreciation & Amortization Expense	12,774,942	12,801,248	12,820,097	12,846,749	12,878,007	12,908,595	12,938,585	12,962,105	12,997,711	13,033,250	13,231,207	13,576,441	155,768,937
Current Income taxes	11,115,543	8,974,946	5,681,555	2,783,827	4,441,525	7,343,646	10,624,890	10,869,956	6,312,334	2,993,571	5,170,670	9,101,332	85,413,796
Property and Other Taxes	2,744,977	2,747,728	2,746,726	2,746,898	2,746,304	2,747,656	2,749,851	2,750,353	2,750,002	2,748,622	2,752,912	2,751,759	32,983,788
Amortization of Investment Tax Credit	(149,065)	(149,065)	(149,065)	(149,065)	(149,065)	(149,065)	(149,065)	(149,065)	(149,065)	(149,065)	(149,065)	(149,065)	(1,788,780)
Total Operating Expenses	128,405,865	120,135,501	110,304,299	94,116,672	96,067,751	100,623,376	106,847,417	107,479,664	96,080,456	93,802,896	102,339,472	123,979,566	1,280,182,933
Net Operating Income	22,054,145	18,687,054	15,036,635	8,960,425	11,574,470	17,673,289	21,311,018	21,704,251	16,076,894	9,351,832	12,798,019	20,513,311	195,741,342
Other Income less deductions	(226,816)	(127,020)	(201,038)	(420,380)	(116,027)	(73,597)	(103,974)	(136,785)	(60,775)	(110,117)	(76,778)	(106,725)	(1,760,033)
Income before Interest Charges	21,827,329	18,560,034	14,835,597	8,540,044	11,458,443	17,599,692	21,207,044	21,567,466	16,016,119	9,241,715	12,721,240	20,406,586	193,981,309
Interest Charges	4,194,030	4,189,202	4,186,709	4,187,009	4,197,358	4,212,848	4,221,814	4,230,163	4,236,451	4,249,217	4,275,888	4,292,329	50,673,018
Net Income	17,633,299	14,370,832	10,648,888	4,353,035	7,261,085	13,386,844	16,985,230	17,337,303	11,779,668	4,992,498	8,445,352	16,114,257	143,308,291

2014 Budget - Louisville Gas and Electric Company - Total Electric

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Electric Operating Revenues	96,680,418	91,859,691	91,142,955	83,519,403	92,689,957	106,443,959	116,952,321	117,680,101	100,126,444	85,524,299	85,036,223	95,336,279	1,162,992,050
Total Operating Revenues	96,680,418	91,859,691	91,142,955	83,519,403	92,689,957	106,443,959	116,952,321	117,680,101	100,126,444	85,524,299	85,036,223	95,336,279	1,162,992,050
Operating Expenses													
Fuel for Electric Generation	36,872,763	36,521,915	35,252,961	30,507,924	33,723,489	36,852,738	41,236,510	41,676,007	34,148,875	28,916,129	29,773,246	34,718,999	420,201,557
Power Purchased	3,797,848	3,278,775	3,773,739	3,430,798	3,885,191	3,706,808	3,819,066	3,965,259	3,350,612	3,922,459	3,558,781	3,492,233	43,981,568
Other Operation Expenses	17,658,689	16,427,716	16,675,498	16,292,413	17,671,002	19,588,489	18,443,441	18,781,825	18,671,602	17,565,677	16,301,048	18,141,635	212,219,035
Maintenance	6,291,854	6,900,812	9,031,438	10,366,753	8,885,735	7,915,581	7,834,455	7,122,215	8,153,731	11,107,593	9,981,630	7,368,435	100,960,232
Depreciation & Amortization Expense	10,219,954	10,240,998	10,256,078	10,277,399	10,302,406	10,326,876	10,350,868	10,369,684	10,398,169	10,426,600	10,584,966	10,861,153	124,615,150
Current Income Taxes	8,876,948	7,164,470	4,545,244	2,211,575	3,537,734	5,874,917	8,484,425	8,680,478	5,049,867	2,379,370	4,121,050	7,281,066	68,207,144
Property and Other Taxes	2,195,982	2,198,182	2,197,381	2,197,518	2,197,043	2,198,125	2,199,881	2,200,282	2,200,002	2,198,898	2,202,330	2,201,407	26,387,030
Amortization of Investment Tax Credit	(141,612)	(141,612)	(141,612)	(141,612)	(141,612)	(141,612)	(141,612)	(141,612)	(141,612)	(141,612)	(141,612)	(141,612)	(1,699,341)
Total Operating Expenses	85,772,425	82,591,257	81,590,727	75,142,769	80,060,988	86,321,922	92,227,034	92,654,138	81,831,246	76,375,115	76,381,438	83,923,316	994,872,376
Net Operating Income - Electric	10,907,992	9,268,433	9,552,228	8,376,635	12,628,969	20,122,037	24,725,287	25,025,963	18,295,198	9,149,184	8,654,784	11,412,963	168,119,675
Other Income less deductions	(181,453)	(101,616)	(160,831)	(336,304)	(92,821)	(58,878)	(83,179)	(109,428)	(48,620)	(88,094)	(61,423)	(85,380)	(1,408,026)
Income before Interest Charges	10,726,540	9,166,818	9,391,397	8,040,330	12,536,147	20,063,160	24,642,108	24,916,535	18,246,578	9,061,091	8,593,361	11,327,584	166,711,649
Interest Charges	3,355,224	3,351,362	3,349,367	3,349,607	3,357,886	3,370,278	3,377,451	3,384,130	3,389,161	3,399,374	3,420,710	3,433,863	40,538,414
Net Income - Electric	7,371,316	5,815,456	6,042,030	4,690,723	9,178,261	16,692,881	21,264,657	21,532,404	14,857,417	5,661,717	5,172,651	7,893,720	126,173,234

2014 Budget - Louisville Gas and Electric Company - Total Gas

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total
INCOME STATEMENT													
Operating Revenues													
Gas Operating Revenues	53,779,592.54	46,962,864.07	34,197,978.58	19,557,693.31	14,952,263.20	11,852,705.36	11,206,114.64	11,503,813.14	12,030,906.00	17,630,428.68	30,101,267.73	49,156,597.85	312,932,225
Total Operating Revenues	53,779,593	46,962,864	34,197,979	19,557,693	14,952,263	11,852,705	11,206,115	11,503,813	12,030,906	17,630,429	30,101,268	49,156,598	312,932,225
Operating Expenses													
Gas Supply Expenses	31,446,711	27,152,403	18,690,946	9,061,630	5,895,573	3,310,642	3,034,743	3,096,995	3,548,918	7,136,463	15,793,927	28,899,207	157,068,158
Other Operation Expenses	4,527,762	4,276,348	4,484,356	4,520,151	4,581,669	4,969,105	4,847,999	4,897,598	4,881,257	5,007,117	4,434,456	4,565,566	55,993,384
Maintenance	1,323,841	1,202,675	1,296,047	1,708,594	1,508,320	1,429,181	1,466,943	1,506,416	1,414,479	1,521,079	1,490,659	1,513,024	17,381,258
Depreciation & Amortization Expense	2,554,988	2,560,250	2,564,019	2,569,350	2,575,601	2,581,719	2,587,717	2,592,421	2,599,542	2,606,650	2,646,241	2,715,288	31,153,787
Current Income Taxes	2,238,595	1,810,476	1,136,311	572,252	903,792	1,468,729	2,140,465	2,189,478	1,262,467	614,201	1,049,621	1,820,266	17,206,652
Property and Other Taxes	548,995	549,546	549,345	549,380	549,261	549,531	549,970	550,071	550,000	549,724	550,582	550,352	6,596,758
Amortization of Investment Tax Credit	(7,453)	(7,453)	(7,453)	(7,453)	(7,453)	(7,453)	(7,453)	(7,453)	(7,453)	(7,453)	(7,453)	(7,453)	(89,439)
Total Gas Operating Expenses	42,633,440	37,544,244	28,713,571	18,973,903	16,006,763	14,301,454	14,620,383	14,825,525	14,249,210	17,427,781	25,958,033	40,056,250	285,310,558
Net Operating Income - Gas	11,146,153	9,418,620	5,484,407	583,790	(1,054,499)	(2,448,749)	(3,414,269)	(3,321,712)	(2,218,304)	202,648	4,143,235	9,100,348	27,621,667
Other Income less deductions	(45,363)	(25,404)	(40,208)	(84,076)	(23,205)	(14,719)	(20,795)	(27,357)	(12,155)	(22,023)	(15,356)	(21,345)	(352,007)
Income before Interest Charges	11,100,790	9,393,216	5,444,200	499,714	(1,077,705)	(2,463,468)	(3,435,064)	(3,349,069)	(2,230,459)	180,624	4,127,879	9,079,003	27,269,661
Interest Charges	838,806	837,840	837,342	837,402	839,472	842,570	844,363	846,033	847,290	849,843	855,178	858,466	10,134,604
Net Income - Gas	10,261,984	8,555,376	4,606,858	(337,688)	(1,917,176)	(3,306,038)	(4,279,426)	(4,195,102)	(3,077,749)	(669,219)	3,272,701	8,220,537	17,135,057

2015 Budget - Louisville Gas and Electric Company - Total Company

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	Budgeted Base Period[1] **2/28/2015**
INCOME STATEMENT														
Operating Revenues														
Electric Operating Revenues	98,579,802	90,218,128	87,602,952	83,698,796	89,694,810	105,148,881	117,851,537	119,856,158	100,965,100	90,180,208	88,184,851	97,566,921	1,169,548,144	1,163,249,871
Gas Operating Revenues	57,995,450	51,267,997	38,330,676	23,772,302	17,341,499	13,177,547	12,395,071	12,805,842	13,409,423	17,998,686	30,588,047	49,833,638	338,916,177	321,453,215
Total Operating Revenues	156,575,252	141,486,125	125,933,628	107,471,098	107,036,308	118,326,428	130,246,609	132,662,000	114,374,523	108,178,894	118,772,897	147,400,559	1,508,464,321	1,484,703,087
Operating Expenses														
Fuel for Electric Generation	35,281,257	29,988,677	29,973,668	28,243,865	26,557,950	31,512,460	34,845,962	35,957,621	28,068,453	28,937,876	28,514,566	31,170,072	369,052,427	412,076,813
Power Purchased	4,152,438	4,093,109	3,570,714	3,904,995	5,678,929	6,162,638	7,075,780	6,866,229	5,584,640	4,170,775	4,293,160	5,376,675	60,930,082	45,150,492
Gas Supply Expenses	34,392,896	29,868,245	21,024,602	11,064,520	6,617,444	3,638,567	3,052,366	3,179,579	3,656,707	6,506,164	15,171,535	28,463,343	166,635,968	162,730,185
Other Operation Expenses	22,997,846	21,577,701	22,662,758	24,503,887	21,429,560	22,494,022	22,614,866	22,568,919	22,547,016	21,702,383	20,620,405	22,646,430	268,365,793	269,897,451
Maintenance	7,258,433	7,489,590	9,948,085	22,051,273	9,209,544	8,345,188	8,581,641	8,049,232	8,430,786	12,754,641	7,951,976	7,244,887	117,315,275	117,370,330
Depreciation & Amortization Expense	14,018,554	14,037,804	14,085,615	14,133,715	13,724,494	13,344,399	13,415,358	13,481,455	13,556,203	13,610,635	13,763,537	14,022,651	165,194,420	158,249,105
Current Income Taxes	12,003,503	10,443,104	5,673,449	(1,580,810)	6,284,643	8,832,733	12,833,694	13,568,090	8,707,222	4,274,758	7,476,200	10,476,158	98,992,745	87,769,914
Property and Other Taxes	3,230,747	3,233,237	3,230,426	3,232,285	3,232,446	3,231,654	3,235,135	3,235,825	3,235,108	3,234,601	3,237,841	3,237,822	38,807,127	33,955,067
Amortization of Investment Tax Credit	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(111,553)	(1,338,634)	(1,713,756)
Total Operating Expenses	133,224,121	120,619,914	110,057,765	105,442,177	92,623,457	97,450,108	105,543,248	106,795,397	93,674,582	95,080,280	100,917,667	122,526,486	1,283,955,203	1,285,485,602
Net Operating Income	23,351,131	20,866,211	15,875,863	2,028,920	14,412,851	20,876,319	24,703,360	25,866,603	20,699,941	13,098,614	17,855,231	24,874,073	224,509,117	199,217,485
Other Income less deductions	(242,137)	(73,008)	(119,127)	(351,491)	(93,188)	(95,583)	(68,124)	(110,928)	(97,247)	(84,034)	(56,434)	(106,898)	(1,498,199)	(1,721,343)
Income before Interest Charges	23,108,994	20,793,202	15,756,736	1,677,430	14,319,663	20,780,736	24,635,236	25,755,675	20,602,694	13,014,580	17,798,797	24,767,176	223,010,918	197,496,142
Interest Charges	4,371,824	4,337,813	4,371,643	4,386,414	4,416,124	4,409,830	4,420,078	4,429,809	4,430,591	6,258,802	5,986,932	5,826,265	57,646,125	50,999,423
Net Income	18,737,170	16,455,389	11,385,093	(2,708,984)	9,903,539	16,370,906	20,215,158	21,325,866	16,172,103	6,755,778	11,811,865	18,940,911	165,364,793	146,496,719

Budgeted Base Period[1] = The sum of March 2014 through December 2014 totals per the 2014 Budget plus January 2015 through February 2015 totals per the 2015 Budget.

2015 Budget - Louisville Gas and Electric Company - Total Electric

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	Budgeted Base Period[1] **2/28/2015**
INCOME STATEMENT														
Operating Revenues														
Electric Operating Revenues	98,579,802	90,218,128	87,602,952	83,698,796	89,694,810	105,148,881	117,851,537	119,856,158	100,965,100	90,180,208	88,184,851	97,566,921	1,169,548,144	1,163,249,871
Total Operating Revenues	98,579,802	90,218,128	87,602,952	83,698,796	89,694,810	105,148,881	117,851,537	119,856,158	100,965,100	90,180,208	88,184,851	97,566,921	1,169,548,144	1,163,249,871
Operating Expenses														
Fuel for Electric Generation	35,281,257	29,988,677	29,973,668	28,243,865	26,557,950	31,512,460	34,845,962	35,957,621	28,068,453	28,937,876	28,514,566	31,170,072	369,052,427	412,076,813
Power Purchased	4,152,438	4,093,109	3,570,714	3,904,995	5,678,929	6,162,638	7,075,780	6,866,229	5,584,640	4,170,775	4,293,160	5,376,675	60,930,082	45,150,492
Other Operation Expenses	18,281,570	17,176,937	18,149,383	20,029,922	16,902,611	17,789,194	17,887,644	17,786,853	17,780,709	16,915,447	16,025,234	17,639,772	212,365,277	213,591,137
Maintenance	5,762,839	6,086,887	8,421,869	20,270,393	7,509,579	6,592,373	6,655,394	6,283,808	6,541,852	10,192,270	6,308,015	5,624,242	96,249,522	99,617,292
Depreciation & Amortization Expense	11,372,110	11,382,251	11,417,406	11,451,412	11,026,976	10,628,608	10,681,185	10,730,799	10,788,861	10,825,546	10,963,413	11,182,665	132,451,232	126,908,559
Current Income Taxes	6,882,924	6,021,770	2,998,430	(2,422,922)	6,211,463	9,363,168	13,478,600	14,068,654	9,253,289	4,509,729	5,738,900	6,623,753	82,727,757	65,070,420
Property and Other Taxes	2,480,141	2,482,131	2,457,957	2,459,426	2,459,553	2,458,928	2,461,574	2,462,119	2,461,553	2,461,152	2,463,712	2,463,697	29,571,945	26,955,139
Amortization of Investment Tax Credit	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(105,076)	(1,260,914)	(1,626,270)
Total Operating Expenses	84,108,203	77,126,686	76,884,351	83,832,015	76,241,986	84,402,292	92,981,063	94,051,007	80,374,281	77,907,719	74,201,924	79,975,801	982,087,327	979,776,273
Net Operating Income - Electric	14,471,599	13,091,442	10,718,602	(133,220)	13,452,824	20,746,589	24,870,474	25,805,151	20,590,819	12,272,489	13,982,926	17,591,120	187,460,816	175,506,290
Other Income less deductions	(191,240)	(57,628)	(94,062)	(277,629)	(73,570)	(75,462)	(53,770)	(87,585)	(76,777)	(65,889)	(44,083)	(84,401)	(1,182,097)	(1,373,826)
Income before Interest Charges	14,280,359	13,033,814	10,624,540	(410,849)	13,379,254	20,671,127	24,816,705	25,717,566	20,514,042	12,206,600	13,938,843	17,506,719	186,278,719	174,132,464
Interest Charges	3,541,177	3,513,628	3,541,031	3,552,995	3,577,061	3,571,962	3,580,263	3,588,145	3,588,778	5,069,629	4,849,415	4,719,275	46,693,360	40,886,634
Net Income - Electric	10,739,182	9,520,185	7,083,509	(3,963,844)	9,802,193	17,099,165	21,236,441	22,129,421	16,925,264	7,136,971	9,089,428	12,787,444	139,585,359	133,245,830

2015 Budget - Louisville Gas and Electric Company - Total Gas

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	Budgeted Base Period[1] **2/28/2015**
INCOME STATEMENT														
Operating Revenues														
Gas Operating Revenues	57,995,450	51,267,997	38,330,676	23,772,302	17,341,499	13,177,547	12,395,071	12,805,842	13,409,423	17,998,686	30,588,047	49,833,638	338,916,177	321,453,215
Total Operating Revenues	57,995,450	51,267,997	38,330,676	23,772,302	17,341,499	13,177,547	12,395,071	12,805,842	13,409,423	17,998,686	30,588,047	49,833,638	338,916,177	321,453,215
Operating Expenses														
Gas Supply Expenses	34,392,896	29,868,245	21,024,602	11,064,520	6,617,444	3,638,567	3,052,366	3,179,579	3,656,707	6,506,164	15,171,535	28,463,343	166,635,968	162,730,185
Other Operation Expenses	4,716,276	4,400,764	4,513,376	4,473,965	4,526,949	4,704,828	4,727,222	4,782,066	4,766,306	4,786,936	4,595,171	5,006,658	56,000,517	56,306,314
Maintenance	1,495,594	1,402,703	1,526,216	1,780,879	1,699,965	1,752,815	1,926,246	1,765,424	1,888,934	2,562,371	1,643,960	1,620,645	21,065,753	17,753,038
Depreciation & Amortization Expense	2,646,444	2,655,553	2,668,210	2,682,303	2,697,518	2,715,791	2,734,173	2,750,656	2,767,342	2,785,089	2,800,124	2,839,986	32,743,188	31,340,546
Current Income Taxes	5,120,580	4,421,334	2,675,019	842,112	73,180	(530,435)	(644,906)	(500,563)	(546,067)	(234,971)	1,737,300	3,852,405	16,264,988	22,699,495
Property and Other Taxes	750,606	751,106	772,469	772,859	772,893	772,726	773,561	773,706	773,555	773,449	774,129	774,125	9,235,182	6,999,928
Amortization of Investment Tax Credit	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(6,477)	(77,720)	(87,486)
Total Gas Operating Expenses	49,115,918	43,493,229	33,173,414	21,610,162	16,381,472	13,047,816	12,562,186	12,744,390	13,300,301	17,172,561	26,715,742	42,550,685	301,867,876	297,742,021
Net Operating Income - Gas	8,879,532	7,774,769	5,157,261	2,162,140	960,027	129,730	(167,114)	61,452	109,122	826,125	3,872,304	7,282,953	37,048,301	23,711,194
Other Income less deductions	(50,897)	(15,380)	(25,065)	(73,861)	(19,618)	(20,121)	(14,354)	(23,343)	(20,470)	(18,146)	(12,350)	(22,496)	(316,102)	(347,517)
Income before Interest Charges	8,828,634	7,759,389	5,132,196	2,088,279	940,409	109,609	(181,469)	38,109	88,652	807,979	3,859,954	7,260,457	36,732,199	23,363,678
Interest Charges	830,646	824,184	830,612	833,419	839,064	837,868	839,815	841,664	841,812	1,189,172	1,137,517	1,106,990	10,952,763	10,112,788
Net Income - Gas	7,997,988	6,935,204	4,301,584	1,254,860	101,345	(728,258)	(1,021,284)	(803,555)	(753,160)	(381,193)	2,722,437	6,153,467	25,779,436	13,250,890

Budgeted Base Period[1] = The sum of March 2014 through December 2014 totals per the 2014 Budget plus January 2015 through February 2015 totals per the 2015 Budget.

2016 Budget - Louisville Gas and Electric Company - Total Company

														Test Year
	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	**6/30/2016**
INCOME STATEMENT														
Operating Revenues														
Electric Operating Revenues	100,634,324	95,052,933	91,328,703	88,420,382	93,192,935	110,317,542	121,026,344	123,822,959	104,794,673	90,989,005	89,479,672	99,210,969	1,208,270,441	1,193,551,594
Gas Operating Revenues	58,767,705	51,986,253	38,967,070	24,399,055	17,933,815	13,788,973	13,660,917	14,130,746	14,709,486	19,417,696	32,510,309	52,235,526	352,507,550	342,873,578
Total Operating Revenues	159,402,029	147,039,186	130,295,772	112,819,437	111,126,750	124,106,514	134,687,261	137,953,705	119,504,159	110,406,701	121,989,981	151,446,495	1,560,777,992	1,536,425,171
Operating Expenses														
Fuel for Electric Generation	32,161,345	28,310,767	27,140,280	29,032,351	25,259,201	31,197,762	35,600,856	36,901,247	29,349,780	26,370,680	27,444,111	31,803,804	360,572,184	360,596,257
Power Purchased	5,676,035	6,807,947	5,555,767	3,821,174	6,023,012	6,931,008	6,336,417	6,598,172	5,074,207	4,375,747	4,032,265	4,020,358	65,252,110	68,182,203
Gas Supply Expenses	34,701,825	30,120,307	21,162,765	11,192,626	6,705,616	3,716,530	2,972,908	3,147,610	3,616,802	6,600,977	15,771,027	29,572,122	169,281,115	167,629,363
Other Operation Expenses	22,074,668	21,977,080	22,389,743	20,646,738	22,281,731	23,143,059	23,378,215	24,834,131	24,039,565	22,892,942	22,485,103	22,767,102	272,910,077	265,213,039
Maintenance	7,362,154	7,563,545	10,292,241	11,308,496	10,773,143	9,762,284	8,147,691	8,841,033	9,556,021	11,747,999	8,894,775	7,529,087	111,778,467	110,075,024
Depreciation & Amortization Expense	14,158,915	14,175,894	14,199,061	14,232,228	14,291,286	14,581,076	14,854,305	14,901,039	14,942,834	14,982,590	15,030,348	15,234,513	175,584,089	167,488,297
Current Income Taxes	13,085,585	11,094,606	7,144,907	5,038,768	6,271,581	9,138,767	13,114,187	12,849,980	8,400,178	5,319,186	7,213,695	11,323,366	109,994,807	109,110,336
Property and Other Taxes	3,589,379	3,589,337	3,586,243	3,590,466	3,588,301	3,588,695	3,594,769	3,590,736	3,592,532	3,593,210	3,594,231	3,596,788	43,094,687	40,948,753
Amortization of Investment Tax Credit	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(102,436)	(1,229,230)	(1,283,934)
Total Operating Expenses	132,707,470	123,537,047	111,368,571	98,760,412	95,091,437	101,956,745	107,896,912	111,561,512	98,469,483	95,780,895	104,363,118	125,744,705	1,307,238,305	1,287,959,338
Net Operating Income	26,694,558	23,502,139	18,927,201	14,059,026	16,035,314	22,149,770	26,790,349	26,392,193	21,034,676	14,625,806	17,626,863	25,701,791	253,539,686	248,465,833
Other Income less deductions	(237,203)	(78,223)	(125,942)	(349,906)	(101,152)	(107,954)	(78,966)	(121,789)	(105,320)	(105,617)	(85,779)	(107,431)	(1,605,283)	(1,524,045)
Income before Interest Charges	26,457,356	23,423,916	18,801,259	13,709,120	15,934,162	22,041,815	26,711,382	26,270,403	20,929,356	14,520,190	17,541,084	25,594,359	251,934,404	246,941,788
Interest Charges	6,024,751	5,959,548	5,977,441	6,028,304	6,068,219	6,068,265	6,075,614	6,092,446	6,113,269	6,154,633	6,179,997	6,188,949	72,931,435	67,479,003
Net Income	20,432,605	17,464,368	12,823,819	7,680,816	9,865,943	15,973,550	20,635,768	20,177,958	14,816,087	8,365,556	11,361,088	19,405,410	179,002,969	179,462,784

2016 Budget - Louisville Gas and Electric Company - Total Electric

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	**Test Year 6/30/2016**
INCOME STATEMENT														
Operating Revenues														
Electric Operating Revenues	100,634,324	95,052,933	91,328,703	88,420,382	93,192,935	110,317,542	121,026,344	123,822,959	104,794,673	90,989,005	89,479,672	99,210,969	1,208,270,441	1,193,551,594
Total Operating Revenues	100,634,324	95,052,933	91,328,703	88,420,382	93,192,935	110,317,542	121,026,344	123,822,959	104,794,673	90,989,005	89,479,672	99,210,969	1,208,270,441	1,193,551,594
Operating Expenses														
Fuel for Electric Generation	32,161,345	28,310,767	27,140,280	29,032,351	25,259,201	31,197,762	35,600,856	36,901,247	29,349,780	26,370,680	27,444,111	31,803,804	360,572,184	360,596,257
Power Purchased	5,676,035	6,807,947	5,555,767	3,821,174	6,023,012	6,931,008	6,336,417	6,598,172	5,074,207	4,375,747	4,032,265	4,020,359	65,252,110	68,182,202
Other Operation Expenses	17,364,880	17,376,404	17,634,915	16,301,435	17,632,432	18,418,074	17,930,476	19,047,914	18,391,849	17,259,323	16,941,703	17,077,024	211,376,429	208,763,799
Maintenance	5,881,580	6,109,525	8,718,646	9,676,122	9,057,913	7,968,963	6,453,722	7,055,133	7,129,961	10,018,556	7,242,233	5,961,217	91,273,572	89,018,332
Depreciation & Amortization Expense	11,278,536	11,284,877	11,296,362	11,314,915	11,358,306	11,631,222	11,887,363	11,915,877	11,938,836	11,958,124	11,984,614	12,148,785	139,997,818	133,336,688
Current Income Taxes	8,029,669	6,840,997	4,625,806	4,139,153	6,300,852	9,726,481	13,670,241	13,466,661	9,220,839	5,161,369	5,475,222	7,363,384	94,020,673	93,335,883
Property and Other Taxes	2,735,723	2,735,690	2,733,246	2,736,582	2,734,871	2,735,183	2,739,876	2,736,690	2,738,109	2,738,644	2,739,451	2,741,471	32,845,534	31,185,102
Amortization of Investment Tax Credit	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(97,401)	(1,168,810)	(1,214,862)
Total Operating Expenses	83,030,367	79,368,806	77,607,621	76,924,333	78,269,187	88,511,292	94,521,551	97,624,293	83,746,179	77,785,042	75,762,197	81,018,643	994,169,511	983,203,401
Net Operating Income - Electric	17,603,957	15,684,127	13,721,082	11,496,049	14,923,748	21,806,250	26,504,793	26,198,666	21,048,494	13,203,964	13,717,475	18,192,326	214,100,931	210,348,193
Other Income less deductions	(187,295)	(61,700)	(99,398)	(276,328)	(79,814)	(85,188)	(62,287)	(96,118)	(83,107)	(83,340)	(67,670)	(84,774)	(1,267,020)	(1,202,228)
Income before Interest Charges	17,416,662	15,622,427	13,621,684	11,219,721	14,843,934	21,721,062	26,442,506	26,102,547	20,965,387	13,120,623	13,649,806	18,107,552	212,833,911	209,145,965
Interest Charges	4,880,048	4,827,234	4,841,727	4,882,926	4,915,257	4,915,295	4,921,248	4,934,881	4,951,748	4,985,253	5,005,797	5,013,049	59,074,462	54,657,993
Net Income - Electric	12,536,614	10,795,193	8,779,957	6,336,795	9,928,677	16,805,767	21,521,258	21,167,666	16,013,639	8,135,370	8,644,008	13,094,503	153,759,449	154,487,972

2016 Budget - Louisville Gas and Electric Company - Total Gas

	January	February	March	April	May	June	July	August	September	October	November	December	Year Total	**Test Year 6/30/2016**
INCOME STATEMENT														
Operating Revenues														
Gas Operating Revenues	58,767,705	51,986,253	38,967,070	24,399,055	17,933,815	13,788,973	13,660,917	14,130,746	14,709,486	19,417,696	32,510,309	52,235,526	352,507,550	342,873,578
Total Operating Revenues	58,767,705	51,986,253	38,967,070	24,399,055	17,933,815	13,788,973	13,660,917	14,130,746	14,709,486	19,417,696	32,510,309	52,235,526	352,507,550	342,873,578
Operating Expenses														
Gas Supply Expenses	34,701,825	30,120,307	21,162,765	11,192,626	6,705,616	3,716,530	2,972,908	3,147,610	3,616,802	6,600,977	15,771,027	29,572,122	169,281,115	167,629,363
Other Operation Expenses	4,709,789	4,600,676	4,754,828	4,345,302	4,649,299	4,724,986	5,447,739	5,786,218	5,647,715	5,633,619	5,543,400	5,690,078	61,533,648	56,449,241
Maintenance	1,480,574	1,454,020	1,573,594	1,632,374	1,715,230	1,793,320	1,693,968	1,785,899	2,426,060	1,729,444	1,652,541	1,567,871	20,504,894	21,056,692
Depreciation & Amortization Expense	2,880,379	2,891,016	2,902,699	2,917,313	2,932,980	2,949,854	2,966,942	2,985,161	3,003,998	3,024,466	3,045,734	3,085,728	35,586,271	34,151,610
Current Income Taxes	5,055,916	4,253,609	2,519,101	899,615	(29,271)	(587,714)	(556,054)	(616,681)	(820,660)	157,818	1,738,473	3,959,982	15,974,134	15,774,454
Property and Other Taxes	853,656	853,647	852,997	853,884	853,430	853,512	854,893	854,046	854,423	854,566	854,780	855,317	10,249,153	9,763,651
Amortization of Investment Tax Credit	(5,037)	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(5,035)	(5,033)	(60,420)	(69,072)
Total Gas Operating Expenses	49,677,101	44,168,241	33,760,950	21,836,079	16,822,249	13,445,453	13,375,361	13,937,219	14,723,304	17,995,853	28,600,921	44,726,064	313,068,795	304,755,938
														-
Net Operating Income - Gas	9,090,604	7,818,012	5,206,119	2,562,977	1,111,565	343,520	285,555	193,527	(13,818)	1,421,843	3,909,388	7,509,462	39,438,755	38,117,639
Other Income less deductions	(49,908)	(16,523)	(26,544)	(73,577)	(21,338)	(22,766)	(16,679)	(25,672)	(22,213)	(22,276)	(18,110)	(22,657)	(338,264)	(321,817)
Income before Interest Charges	9,040,695	7,801,489	5,179,575	2,489,400	1,090,227	320,753	268,876	167,856	(36,031)	1,399,567	3,891,279	7,486,805	39,100,492	37,795,822
Interest Charges	1,144,703	1,132,314	1,135,714	1,145,378	1,152,962	1,152,970	1,154,367	1,157,565	1,161,521	1,169,380	1,174,199	1,175,900	13,856,973	12,821,011
Net Income - Gas	7,895,993	6,669,175	4,043,861	1,344,022	(62,735)	(832,217)	(885,491)	(989,709)	(1,197,552)	230,187	2,717,079	6,310,905	25,243,519	24,974,812

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(e)
Sponsoring Witness: Victor S. Staffieri

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.

Victor A. Staffieri

VICTOR A. STAFFIERI
Chairman of the Board, 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 20th day of November 2014.

(SEAL)
Notary Public

My Commission Expires:
March 29, 2018

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(f)
Sponsoring Witness: Russel A. Hudson

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.

Louisville Gas and Electric Company
Case No. 2014-00372
Fully Forecasted Test Period
Summary of Electric Capital Construction Forecast which Constitute More than five (5%) of the Total and all other Projects

Year 2014

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/14 Without AFUDC	AFUDC	Inception-to-Date 8/31/14 With AFUDC	Expected Start Date	Expected Completion Date
Mill Creek	MC1&2 FGD, MC1FF, MC2FF	1 & 2	$ 151,901,924	$ -	$ 151,901,924	$ 201,682,812	$ -	$ 201,682,812	Dec-11	May-15
Trimble County	TC1 FABRIC FILTER	1	$ 40,523,523	$ -	$ 40,523,523	$ 34,682,384	$ -	$ 34,682,384	Nov-11	Nov-15
Mill Creek	MC4 FGD, FF	4	$ 162,424,869	$ -	$ 162,424,869	$ 266,339,137	$ -	$ 266,339,137	Nov-11	Dec-14
	All Other Projects < 5%		$ 236,712,963	$ -	$ 236,712,963	$ 877,273,057	$ -	$ 877,273,057		

Year 2015

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/14 Without AFUDC	AFUDC	Inception-to-Date 8/31/14 With AFUDC	Expected Start Date	Expected Completion Date
Mill Creek	MC1&2 FGD, MC1FF, MC2FF	1 &2	$ 65,672,080	$ -	$ 65,672,080	$ 201,682,812	$ -	$ 201,682,812	Dec-11	May-15
Mill Creek	MC3 FGD & FABRIC FILTER	3	$ 164,330,796	$ -	$ 164,330,796	$ 61,248,184	$ -	$ 61,248,184	Nov-11	Jun-16
Trimble County	TC1 FABRIC FILTER (Net)	1	$ 60,254,437	$ -	$ 60,254,437	$ 34,682,384	$ -	$ 34,682,384	Nov-11	Nov-15
	All Other Projects < 5%		$ 249,020,098	$ -	$ 249,020,098	$ 657,373,163	$ -	$ 657,373,163		

Year 2016

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/14 Without AFUDC	AFUDC	Inception-to-Date 8/31/14 With AFUDC	Expected Start Date	Expected Completion Date
Mill Creek	MC3 FGD & FABRIC FILTER	3	$ 49,183,620	$ -	$ 49,183,620	$ 61,248,184	$ -	$ 61,248,184	Nov-11	Jun-16
Mill Creek	Mill Creek 51 MERC	N/A	$ 25,000,000	$ -	$ 25,000,000	$ -	$ -	$ -	Jul-15	Dec-18
Trimble County	TC CCP Landfill Phase I	N/A	$ 22,490,000	$ -	$ 22,490,000	$ 11,173,020	$ -	$ 11,173,020	Mar-10	Apr-18
Trimble County	TC CCR Treatment LGE (Net)	N/A	$ 35,420,000	$ -	$ 35,420,000	$ -	$ -	$ -	Jul-15	Dec-17
	All Other Projects < 5%		$ 263,929,586	-	$ 263,929,586	$ 598,177,537	$ -	$ 598,177,537		

Year 2017

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/14 Without AFUDC	AFUDC	Inception-to-Date 8/31/14 With AFUDC	Expected Start Date	Expected Completion Date
Mill Creek	Mill Creek Landfill Expansion	N/A	$ 38,663,380	$ -	$ 38,663,380	$ -	$ -	$ -	Jun-15	Dec-19
Mill Creek	Mill Creek 51 MERC	N/A	$ 50,000,000	$ -	$ 50,000,000	$ -	$ -	$ -	Jul-15	Dec-18
Trimble County	Effluent Water - Trimble Co LGE (Net)	N/A	$ 26,000,000	$ -	$ 26,000,000	$ -	$ -	$ -	Jul-15	Dec-18
Trimble County	TC CCR Treatment LGE (Net)	N/A	$ 21,505,000	$ -	$ 21,505,000	$ -	$ -	$ -	Jul-15	Dec-17
	All Other Projects < 5%		$ 240,380,014	-	$ 240,380,014	$ 562,450,726	$ -	$ 562,450,726		

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(f)
Page 1 of 1
K. Blake

Louisville Gas and Electric Company
Case No. 2014-00372
Fully Forecasted Test Period
Summary of Gas Capital Construction Forecast which Constitute More than five (5%) of the Total and all other Projects

Year 2014

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/14 Without AFUDC	AFUDC	Inception-to-Date 8/31/14 With AFUDC	Expected Start Date	Expected Completion Date
NA	Large Scale Main Replacement	NA	$ 8,363,000	-	$ 8,363,000	$ 126,375,000	$ -	$ 126,375,000	Jan-04	Dec-16
NA	Downtown Main Replacement	NA	$ 9,699,000	-	$ 9,699,000	$ 17,014,000	$ -	$ 17,014,000	Jan-04	Dec-17
NA	Gas Service Riser Replacement	NA	$ 22,061,000	-	$ 22,061,000	$ 31,412,000	$ -	$ 31,412,000	Jan-13	Dec-17
	All Other Projects < 5%		$ 46,086,570	-	$ 46,086,570	$ 168,059,576	$ -	$ 168,059,576		

Year 2015

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/14 Without AFUDC	AFUDC	Inception-to-Date 8/31/14 With AFUDC	Expected Start Date	Expected Completion Date
NA	Large Scale Main Replacement	NA	$ 9,722,000	-	$ 9,722,000	$ 126,375,000	$ -	$ 126,375,000	Jan-04	Dec-16
NA	Downtown Main Replacement	NA	$ 9,016,000	-	$ 9,016,000	$ 17,014,000	$ -	$ 17,014,000	Jan-04	Dec-17
NA	Priority Main Replacement	NA	$ 4,572,000	-	$ 4,572,000	$ 21,906,000	$ -	$ 21,906,000	Jan-04	Dec-16
NA	Gas Service Riser Replacement	NA	$ 22,992,000	-	$ 22,992,000	$ 31,412,000	$ -	$ 31,412,000	Jan-13	Dec-17
	All Other Projects < 5%		$ 46,351,578	-	$ 46,351,578	$ 31,335,585	$ -	$ 31,335,585		

Year 2016

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/14 Without AFUDC	AFUDC	Inception-to-Date 8/31/14 With AFUDC	Expected Start Date	Expected Completion Date
NA	Downtown Main Replacement	NA	$ 21,927,000	-	$ 21,927,000	$ 17,014,000	$ -	$ 17,014,000	Jan-10	Dec-17
NA	Gas Service Riser Replacement	NA	$ 23,522,000	-	$ 23,522,000	$ 31,412,000	$ -	$ 31,412,000	Jan-13	Dec-17
	All Other Projects < 5%		$ 50,041,074	-	$ 50,041,074	$ 179,074,930	$ -	$ 179,074,930		

Year 2017

Plant	Project Description	Unit	Project Amount Without AFUDC	AFUDC	Project Amount With AFUDC	Inception-to-Date 8/31/14 Without AFUDC	AFUDC	Inception-to-Date 8/31/14 With AFUDC	Expected Start Date	Expected Completion Date
NA	Downtown Main Replacement	NA	$ 5,000,000	-	$ 5,000,000	$ 17,014,000	$ -	$ 17,014,000	Jan-10	Dec-17
NA	Gas Service Riser Replacement	NA	$ 19,026,000	-	$ 19,026,000	$ 31,412,000	$ -	$ 31,412,000	Jan-13	Dec-17
NA	Beltline Priority	NA	$ 5,000,000	-	$ 5,000,000	$ -	$ -	$ -	Jan-17	Dec-19
NA	Customer Service Line Replacements	NA	$ 4,624,000	-	$ 4,624,000	$ 2,934,000	$ -	$ 2,934,000	Jan-13	Ongoing
	All Other Projects <5%		$ 42,525,829	-	$ 42,525,829	$ 19,668,923	$ -	$ 19,668,923		

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(f)

K. Blake

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(g)
Sponsoring Witness: Russel A. Hudson

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 LG&E's response to Filing Requirement 807 KAR 5:001 Section 16(7)(f) [Tab No. 19].

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)
Sponsoring Witnesses: Kent W. Blake

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 LG&E's responses to Tab Nos. 22-38.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(1)
Sponsoring Witnesses: Kent W. Blake

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 increase in rates sought in this case**.**

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Income Statements 2014 - 2017
Base Period: Twelve Months Ended February 28, 2015
Forecasted Test Period: Twelve Months Ended June 30, 2016

Louisville Gas and Electric Company - Total Company	**Income Statements**			
	2014	**2015**	**2016**	**2017**
	$	**$**	**$**	**$**
INCOME STATEMENT				
Operating Revenues				
Electric Operating Revenues	1,180,663,001	1,169,548,144	1,208,270,441	1,254,292,152
Gas Operating Revenues	350,630,898	338,916,177	352,507,550	371,736,719
Total Operating Revenues	1,531,293,899	1,508,464,321	1,560,777,992	1,626,028,872
Operating Expenses	312,024,012			
Fuel for Electric Generation	416,402,593	369,052,427	360,572,184	380,611,433
Power Purchased	47,760,829	60,930,082	65,252,110	69,046,744
Gas Supply Expenses	183,914,535	166,635,968	169,281,115	174,921,640
Other Operation Expenses	265,459,756	268,365,793	272,910,077	289,860,981
Maintenance	112,302,344	117,315,275	111,778,467	118,640,242
Depreciation & Amortization Expense	157,262,723	165,194,420	175,584,089	187,996,613
Current Income Taxes	98,769,043	98,992,745	109,994,807	105,331,222
Property and Other Taxes	36,167,107	38,807,127	43,094,687	45,675,626
Amortization of Investment Tax Credit	(1,788,781)	(1,338,634)	(1,229,230)	(1,107,034)
Loss(Gain) from Disposition of Allowances	(427)			
Total Operating Expenses	1,316,249,722	1,283,955,203	1,307,238,305	1,370,977,467
Net Operating Income	215,044,177	224,509,117	253,539,686	255,051,405
Other Income less deductions	(2,143,660)	(1,498,199)	(1,605,283)	(1,614,460)
Income before Interest Charges	212,900,518	223,010,918	251,934,404	253,436,945
Interest Charges	49,220,452	57,646,125	72,931,435	81,725,495
Net Income	163,680,066	165,364,793	179,002,969	171,711,450

Louisville Gas and Electric Company - Electric

	2014	**2015**	**2016**	**2017**
	$	**$**	**$**	**$**
INCOME STATEMENT				
Operating Revenues				
Electric Operating Revenues	1,180,663,001	1,169,548,144	1,208,270,441	1,254,292,152
Total Operating Revenues	1,180,663,001	1,169,548,144	1,208,270,441	1,254,292,152
Operating Expenses				
Fuel for Electric Generation	416,402,593	369,052,427	360,572,184	380,611,433
Power Purchased	47,760,829	60,930,082	65,252,110	69,046,744
Other Operation Expenses	213,712,012	212,365,277	211,376,429	216,678,837
Maintenance	94,416,281	96,249,522	91,273,572	97,831,541
Depreciation & Amortization Expense	127,589,138	132,451,232	139,997,818	149,563,675
Current Income Taxes	79,036,647	82,727,757	94,020,673	90,686,645
Property and Other Taxes	27,854,891	29,571,945	32,845,534	34,838,137
Amortization of Investment Tax Credit	(1,691,461)	(1,260,914)	(1,168,810)	(1,060,510)
Loss(Gain) from Disposition of Allowances	(427)			
Total Operating Expenses	1,005,080,503	982,087,327	994,169,511	1,038,196,501
Net Operating Income - Electric	175,582,498	187,460,816	214,100,931	216,095,651
Other Income less deductions	(2,923,331)	(1,182,097)	(1,267,020)	(1,272,911)
Income before Interest Charges	172,659,167	186,278,719	212,833,911	214,822,740
Interest Charges	39,868,566	46,693,360	59,074,462	66,197,651
Net Income - Electric	132,790,601	139,585,359	153,759,449	148,625,089

Louisville Gas and Electric Company - Gas

	2014	**2015**	**2016**	**2017**
	$	**$**	**$**	**$**
INCOME STATEMENT				
Operating Revenues				
Gas Operating Revenues	350,630,898	338,916,177	352,507,550	371,736,719
Total Operating Revenues	350,630,898	338,916,177	352,507,550	371,736,719
Operating Expenses	59,096,755			
Gas Supply Expenses	183,914,535	166,635,968	169,281,115	174,921,640
Other Operation Expenses	51,747,743	56,000,517	61,533,648	73,182,144
Maintenance	17,886,063	21,065,753	20,504,894	20,808,701
Depreciation & Amortization	29,673,585	32,743,188	35,586,271	38,432,938
Current Income Taxes	19,732,396	16,264,988	15,974,134	14,644,577
Property and Other Taxes	8,312,216	9,235,182	10,249,153	10,837,489
Amortization of Investment Tax Credit	(97,320)	(77,720)	(60,420)	(46,524)
Total Gas Operating Expenses	311,169,219	301,867,876	313,068,795	332,780,966
Net Operating Income - Gas	39,461,679	37,048,301	39,438,755	38,955,754
Other Income less deductions	779,672	(316,102)	(338,264)	(341,548)
Income before Interest Charges	40,241,351	36,732,199	39,100,492	38,614,205
Interest Charges	9,351,886	10,952,763	13,856,973	15,527,844
Net Income - Gas	30,889,465	25,779,436	25,243,519	23,086,361

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(2)
Sponsoring Witnesses: Kent W. Blake

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 increase in rates sought in this case.

Louisville Gas and Electric Company
Case No. 2014-00372
Balance Sheet - Total Company
Calendar Years 2014 - 2017

	2014	2015	2016	2017
Louisville Gas and Electric Company - Total	$	$	$	$
ASSETS AND OTHER DEBITS				
UTILITY PLANT				
Gross Utility Plant	6,275,787,071	6,488,548,668	6,846,548,068	7,267,317,424
Accumulated Provision for Depreciation and Amortization	(2,342,303,024)	(2,092,906,234)	(2,139,554,626)	(2,300,174,555)
Total Utility Net Plant	**3,933,484,047**	**4,395,642,434**	**4,706,993,442**	**4,967,142,869**
INVESTMENTS				
Investment in Subsidiary Companies	594,286	594,286	594,286	594,286
Net Nonutility property	539,420	539,420	539,420	539,420
Special Funds	21,207,370	21,207,370	21,207,370	21,207,370
Total other Property and Investments	**22,341,077**	**22,341,077**	**22,341,077**	**22,341,077**
CURRENT AND ACCRUED ASSETS				
Cash	5,000,000	5,000,000	5,000,000	5,000,000
Special Deposits and Temporary Cash Investments			6	17
Accounts Receivable - Less Reserves	180,314,159	180,319,694	181,842,168	183,046,299
Accounts Receivable from Associated Companies	18,689,236	18,392,889	19,895,137	22,022,963
Inventories	154,700,135	135,124,852	133,343,861	137,390,284
Prepayments	5,221,338	6,644,460	6,274,024	5,738,648
Other Current and Accrued Assets	23,618	23,618	23,618	23,618
Total Current and Accrued Assets	**363,948,486**	**345,505,513**	**346,378,813**	**353,221,829**
DEFERRED DEBITS AND OTHER				
Unamortized Debt Expenses	30,484,181	27,521,546	25,010,517	22,738,168
Accumulated Deferred Income Tax Asset	125,509,564	125,509,564	125,509,564	125,509,564
Regulatory Assets	313,427,553	287,967,230	272,865,108	262,230,845
Miscellaneous Deferred Debits	3,360,861	5,828,266	4,681,881	5,957,727
Total Deferred Debits & Other	**472,782,160**	**446,826,606**	**428,067,070**	**416,436,303**
TOTAL ASSETS	**4,792,555,769**	**5,210,315,629**	**5,503,780,402**	**5,759,142,078**

Louisville Gas and Electric Company
Case No. 2014-00372
Balance Sheet - Total Company
Calendar Years 2014 - 2017

Louisville Gas and Electric Company - Total	**2014** $	**2015** $	**2016** $	**2017** $
LIABILITIES AND OTHER CREDITS				
PROPRIETARY CAPITAL				
Common and Preferred Stock Issued	350,160,412	351,222,275	351,222,275	351,222,275
Common Stock Expense	(688,418)	(690,506)	(690,506)	(690,506)
Paid-in-capital	271,691,513	397,086,622	449,647,902	487,453,236
Retained Earnings	845,771,325	899,925,398	952,551,533	998,826,090
Other Comprehensive Income				
Total Proprietary Capital	**1,466,934,832**	**1,647,543,789**	**1,752,731,205**	**1,836,811,095**
Total Long-term Debt	**1,115,735,043**	**1,367,202,835**	**1,367,338,047**	**1,573,991,415**
TOTAL CAPITALIZATION	**2,582,669,875**	**3,014,746,624**	**3,120,069,253**	**3,410,802,510**
CURRENT AND ACCRUED LIABILITIES				
Notes Payable	226,896,393	112,569,708	221,969,993	67,794,998
Accounts Payable	245,156,659	245,965,699	246,637,656	246,301,646
Accounts Payable to Associated Companies	16,562,210	22,343,832	30,155,858	37,592,293
Customer Deposits	24,000,007	24,000,007	24,000,007	24,000,007
Taxes Accrued	6,769,130	6,769,130	6,769,129	6,769,128
Interest Accrued	6,490,587	11,886,689	9,991,780	15,004,092
Dividends Payable Affiliate				
Miscellaneous Current Liabilities	52,774,073	53,607,580	54,226,239	54,151,555
Total Current and Accrued Liabilities	**578,649,059**	**477,142,643**	**593,750,661**	**451,613,719**
DEFERRED CREDITS				
Accumulated Deferred Income Tax Liability	748,512,475	788,840,859	866,254,620	935,114,599
Investment Tax Credits	35,982,104	34,643,470	33,414,240	32,307,210
Regulatory Liabilities	80,313,790	73,458,139	70,217,958	66,924,140
Customer Advances for Construction	7,841,391	7,841,391	7,841,391	7,841,391
Asset Retirement Obligations	86,200,087	89,895,369	94,111,609	98,363,431
Other Deferred Credits	17,650,946	17,650,946	17,650,946	17,650,946
Miscellaneous Long Term Liabilities	19,804,550	19,804,550	19,804,550	19,804,550
Accumulated Provision for Post Retirement Benefits	81,681,924	51,551,342	23,749,708	591,637
Electric/Gas Balancing Adjustment	-	-	-	-
Total Deferred Credits	**1,077,987,265**	**1,083,686,064**	**1,133,045,021**	**1,178,597,903**
TOTAL LIABILITIES AND STOCKHOLDER EQUITY	**4,792,555,769**	**5,210,315,629**	**5,503,780,401**	**5,759,142,077**

Louisville Gas and Electric Company
Case No. 2014-00372
Balance Sheet - Electric Utility
Calendar Years 2014 - 2017

	2014	2015	2016	2017
Louisville Gas and Electric Company - Electric Only	$	$	$	$
ASSETS AND OTHER DEBITS				
UTILITY PLANT				
Gross Utility Plant	5,220,372,641	5,346,910,539	5,614,944,574	5,964,954,700
Accumulated Provision for Depreciation and Amortization	(2,023,648,618)	(1,747,041,587)	(1,762,912,345)	(1,889,636,578)
Total Utility Net Plant	**3,196,724,023**	**3,599,868,952**	**3,852,032,229**	**4,075,318,122**
INVESTMENTS				
Investment in Subsidiary Companies	594,286	594,286	594,286	594,286
Net Nonutility property	377,594	377,594	377,594	377,594
Special Funds	17,462,149	17,515,167	17,515,167	17,515,167
Total other Property and Investments	**18,434,029**	**18,487,047**	**18,487,047**	**18,487,047**
CURRENT AND ACCRUED ASSETS				
Cash	4,117,000	4,129,500	4,129,500	4,129,500
Special Deposits and Temporary Cash Investments	0	0	5	14
Accounts Receivable - Less Reserves	139,942,755	139,947,100	141,128,692	142,063,218
Accounts Receivable from Associated Companies	15,402,396	15,204,172	16,444,879	18,202,251
Inventories	101,198,629	83,120,731	79,491,861	81,836,217
Prepayments	4,389,036	5,619,334	5,295,640	4,828,987
Other Current and Accrued Assets	23,618	23,618	23,618	23,618
Total Current and Accrued Assets	**265,073,434**	**248,044,456**	**246,514,194**	**251,083,805**
DEFERRED DEBITS AND OTHER				
Unamortized Debt Expenses	25,100,675	22,730,045	20,656,186	18,779,453
Accumulated Deferred Income Tax Asset	101,323,990	101,323,990	101,323,990	101,323,990
Regulatory Assets	257,132,187	246,666,391	234,626,748	225,858,065
Miscellaneous deferred debits	3,491,696	5,966,895	4,820,510	6,096,356
Total Deferred Debits & Other	**387,048,548**	**376,687,321**	**361,427,434**	**352,057,863**
TOTAL ASSETS	**3,867,280,034**	**4,243,087,777**	**4,478,460,904**	**4,696,946,837**

Louisville Gas and Electric Company
Case No. 2014-00372
Balance Sheet - Electric Utility
Calendar Years 2014 - 2017

Louisville Gas and Electric Company - Electric Only	**2014** $	**2015** $	**2016** $	**2017** $
LIABILITIES AND OTHER CREDITS				
PROPRIETARY CAPITAL				
Common and Preferred Stock Issued	350,085,327	351,148,253	351,148,253	351,148,253
Common Stock Expense	(688,271)	(690,360)	(690,360)	(690,360)
Paid-in-capital	271,633,254	397,002,934	449,553,137	487,350,502
Retained Earnings	845,589,965	899,735,733	952,350,777	998,615,581
Other Comprehensive Income				
Total Proprietary Capital	**1,466,620,276**	**1,647,196,560**	**1,752,361,807**	**1,836,423,976**
Total Long-term Debt	**1,115,495,795**	**1,366,914,689**	**1,367,049,873**	**1,573,659,687**
TOTAL CAPITALIZATION	**2,582,116,072**	**3,014,111,249**	**3,119,411,680**	**3,410,083,663**
CURRENT AND ACCRUED LIABILITIES				
Notes Payable	186,826,490	92,971,322	183,325,017	55,991,889
Accounts Payable	206,859,632	208,195,251	208,696,297	208,272,764
Accounts Payable to Associated Companies	13,637,324	18,453,771	24,905,723	31,047,475
Customer Deposits	19,761,605	19,821,605	19,821,605	19,821,605
Taxes Accrued	5,573,701	5,590,624	5,590,624	5,590,623
Interest Accrued	5,344,349	9,817,216	8,252,211	12,391,880
Dividends Payable Affiliate				
Miscellaneous Current Liabilities	43,454,172	44,274,500	44,785,451	44,723,769
Total Current and Accrued Liabilities	**481,457,274**	**399,124,290**	**495,376,928**	**377,840,006**
DEFERRED CREDITS				
Accumulated Deferred Income Tax Liability	580,275,857	615,443,886	680,827,646	739,300,791
Investment Tax Credits	35,762,058	34,501,144	33,332,334	32,271,824
Regulatory Liabilities	64,437,196	62,013,469	59,398,932	56,665,568
Customer Advances for Construction	1,631,544	1,631,544	1,631,544	1,631,544
Asset Retirement Obligations	64,058,051	66,807,759	69,945,119	73,108,955
Other Deferred Credits	14,533,789	14,577,916	14,577,916	14,577,916
Miscellaneous Long Term Liabilities	16,307,066	16,356,578	16,356,578	16,356,578
Accumulated Provision for Post Retirement Benefits	67,256,896	42,576,253	19,614,884	488,633
Electric/Gas Balancing Adjustment	(40,555,768)	(24,056,310)	(32,012,655)	(25,378,639)
Total Deferred Credits	**803,706,689**	**829,852,238**	**863,672,296**	**909,023,168**
TOTAL LIABILITIES AND STOCKHOLDER EQUITY	**3,867,280,034**	**4,243,087,777**	**4,478,460,904**	**4,696,946,837**

Louisville Gas and Electric Company
Case No. 2014-00372
Balance Sheet - Gas Utility
Calendar Years 2014 - 2017

	2014	2015	2016	2017
Louisville Gas and Electric Company - Gas Only	$	$	$	$
ASSETS AND OTHER DEBITS				
UTILITY PLANT				
Gross Utility Plant	1,055,414,430	1,141,638,129	1,231,603,493	1,302,362,725
Accumulated Provision for Depreciation and Amortization	(318,654,405)	(345,864,648)	(376,642,280)	(410,537,977)
Total Utility Net Plant	**736,760,024**	**795,773,482**	**854,961,213**	**891,824,747**
INVESTMENTS				
Investment in Subsidiary Companies	-	-	-	-
Net Nonutility property	161,826	161,826	161,826	161,826
Special Funds	3,745,222	3,692,203	3,692,203	3,692,203
Total other Property and Investments	**3,907,048**	**3,854,029**	**3,854,029**	**3,854,029**
CURRENT AND ACCRUED ASSETS				
Cash	883,000	870,500	870,500	870,500
Special Deposits and Temporary Cash Investments	-	-	1	3
Accounts Receivable - Less Reserves	40,371,404	40,372,594	40,713,476	40,983,081
Accounts Receivable from Associated Companies	3,286,840	3,188,716	3,450,258	3,820,712
Inventories	53,501,506	52,004,120	53,852,001	55,554,066
Prepayments	832,302	1,025,126	978,384	909,661
Other Current and Accrued Assets	-	-	-	-
Total Current and Accrued Assets	**98,875,052**	**97,461,056**	**99,864,619**	**102,138,024**
DEFERRED DEBITS AND OTHER				
Unamortized Debt Expenses	5,383,506	4,791,501	4,354,331	3,958,715
Accumulated Deferred Income Tax Asset	24,185,574	24,185,574	24,185,574	24,185,574
Regulatory Assets	56,295,366	41,300,839	38,238,360	36,372,780
Miscellaneous deferred debits	(130,835)	(138,629)	(138,629)	(138,629)
Total Deferred Debits & Other	**85,733,612**	**70,139,285**	**66,639,636**	**64,378,440**
TOTAL ASSETS	**925,275,736**	**967,227,853**	**1,025,319,498**	**1,062,195,240**

Louisville Gas and Electric Company
Case No. 2014-00372
Balance Sheet - Gas Utility
Calendar Years 2014 - 2017

(000s) **Louisville Gas and Electric Company - Gas Only**	**2014** $	**2015** $	**2016** $	**2017** $
LIABILITIES AND OTHER CREDITS				
PROPRIETARY CAPITAL				
Common and Preferred Stock Issued	75,085	74,022	74,022	74,022
Common Stock Expense	(148)	(146)	(146)	(146)
Paid-in-capital	58,259	83,688	94,766	102,734
Retained Earnings	181,359	189,665	200,756	210,509
Other Comprehensive Income	-	-	-	-
Total Proprietary Capital	**314,556**	**347,230**	**369,398**	**387,119**
Total Long-term Debt	**239,248**	**288,146**	**288,175**	**331,728**
TOTAL CAPITALIZATION	**553,803**	**635,376**	**657,573**	**718,847**
CURRENT AND ACCRUED LIABILITIES				
Notes Payable	40,069,903	19,598,386	38,644,976	11,803,109
Accounts Payable	38,297,028	37,770,447	37,941,359	38,028,881
Accounts Payable to Associated Companies	2,924,886	3,890,061	5,250,135	6,544,818
Customer Deposits	4,238,401	4,178,401	4,178,401	4,178,401
Taxes Accrued	1,195,428	1,178,505	1,178,505	1,178,505
Interest Accrued	1,146,238	2,069,472	1,739,569	2,612,212
Dividends Payable Affiliate	-	-	-	-
Miscellaneous Current Liabilities	9,319,901	9,333,080	9,440,788	9,427,785
Total Current and Accrued Liabilities	**97,191,785**	**78,018,353**	**98,373,733**	**73,773,713**
DEFERRED CREDITS				
Accumulated Deferred Income Tax Liability	168,236,618	173,396,973	185,426,974	195,813,808
Investment Tax Credits	220,046	142,326	81,906	35,386
Regulatory Liabilities	15,876,594	11,444,670	10,819,026	10,258,573
Customer Advances for Construction	6,209,847	6,209,847	6,209,847	6,209,847
Asset Retirement Obligations	22,142,036	23,087,610	24,166,491	25,254,476
Other Deferred Credits	3,117,157	3,073,030	3,073,030	3,073,030
Miscellaneous Long Term Liabilities	3,497,484	3,447,972	3,447,972	3,447,972
Accumulated Provision for Post Retirement Benefits	14,425,028	8,975,089	4,134,824	103,004
Electric/Gas Balancing Adjustment	40,555,767	24,056,310	32,012,655	25,378,639
Total Deferred Credits	**274,280,576**	**253,833,826**	**269,372,725**	**269,574,735**
TOTAL LIABILITIES AND STOCKHOLDER EQUITY	**925,275,736**	**967,227,853**	**1,025,319,498**	**1,062,195,240**

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(3)
Sponsoring Witnesses: Kent W. Blake

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 increase in rates sought in this case.

Louisville Gas & Electric Company
Case No. 2014-00372
Forecasted Cash Flow Statements 2014 - 2017
Base Period: Twelve Months Ended February 28, 2015
Forecasted Test Period: Twelve Months Ended June 30, 2016

Louisville Gas and Electric Company Cash Flow Statements (a)	**2014**	**2015**	**2016**	**2017**
Cash Flows from Operating Activities				
Net Income	$ 161,244,351	$ 165,364,801	$ 179,002,969	$ 171,711,452
Items not requiring (providing) cash currently:				
Depreciation	157,219,301	165,194,420	175,584,089	187,996,613
Amortization	9,395,013	3,279,907	2,674,709	2,435,583
Deferred Income Taxes and Investment Tax Credits	42,180,094	36,766,066	74,194,167	66,004,050
Change in current assets and current liabilities:				
Change in Customer A/R	4,232,705	290,812	(3,024,722)	(3,331,957)
Change in Inventories	8,614,425	19,821,067	1,973,004	(4,046,422)
Change in Other Current Assets	757,884	(3,890,527)	1,516,821	(740,470)
Change in Regulatory Assets	4,083,984	8,100,172	1,864,433	194,470
Change in Accounts Payable	6,411,648	6,344,878	8,291,969	7,100,425
Change in Taxes Accrued	(3,928,446)	-	-	-
Change in Interest Accrued	(8,006,487)	5,396,102	(1,894,909)	5,012,313
Change in Other Current Liabilities	11,125,777	23,353,171	21,348,491	16,220,164
Other operating activities:				
Pension Cash Payments	(17,479,823)	(31,648,597)	(27,749,170)	(21,728,041)
Other	5,560,265			
Net Cash from Operating Activities	381,410,691	398,372,271	433,781,851	426,828,179
Cash Flows from Investing Activities				
Capital Expenditures for Property, Plant and Equipment	(618,692,216)	(631,930,989)	(491,513,279)	(452,724,223)
Other	(281,400)			
Net Cash from Investing Activities	(618,973,616)	(631,930,989)	(491,513,279)	(452,724,223)
Cash Flows from Financing Activities				
Issuance of Long-Term Debt	-	550,000,000	-	250,000,000
Net (Decrease) Increase in Short-Term Debt	197,096,450	(114,326,685)	109,400,281	(154,175,007)
Capital Contribution Received from Parent	151,226,050	150,799,066	63,627,803	45,765,062
Dividends on common stock	(112,329,840)	(102,913,663)	(115,296,655)	(115,694,011)
Retirement of Long-Term Debt	-	(250,000,000)	-	-
Cost of Issuing or Retiring Debt	(1,432,170)			
Net Cash from Financing Activities	234,560,490	233,558,718	57,731,428	25,896,044
Net Increase in Cash & Cash Equivalents	(3,002,434)	-	-	-
Cash & Cash Equivalents - Beginning of Period	8,022,224	5,019,790	5,019,790	5,019,790
Cash & Cash Equivalents - End of Period	$ 5,019,790	$ 5,019,790	$ 5,019,790	$ 5,019,790

Note - The cash flow statements presented are at the Company level and not at a jurisdictional level.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(4)
Sponsoring Witnesses: Kent W. Blake

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 increase in rates sought in this case.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(h)(4)
Page 1 of 2
Witness: K. Blake

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2014-00372
OVERALL FINANCIAL SUMMARY
FORECAST PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31,

		FORECASTED			
LINE NO.	DESCRIPTION	2014 JURISDICTIONAL REVENUE REQUIREMENT	2015 JURISDICTIONAL REVENUE REQUIREMENT	2016 JURISDICTIONAL REVENUE REQUIREMENT	2017 JURISDICTIONAL REVENUE REQUIREMENT
		$	$	$	$
1	CAPITALIZATION ALLOCATED TO ELECTRIC OPERATIONS (a)	2,064,851,029	2,098,978,385	2,157,769,032	2,310,084,198
2	ADJUSTED OPERATING INCOME	131,519,476	129,495,402	138,027,956	131,331,756
3	EARNED RATE OF RETURN (2 / 1)	6.37%	6.17%	6.40%	5.69%
4	REQUIRED RATE OF RETURN	7.27%	7.24%	7.55%	7.65%
5	REQUIRED OPERATING INCOME (1 x 4)	150,136,700	151,864,622	162,898,571	176,811,999
6	OPERATING INCOME DEFICIENCY (5 - 2)	18,617,223	22,369,220	24,870,615	45,480,243
7	GROSS REVENUE CONVERSION FACTOR	1.608581	1.608581	1.608581	1.608581
8	REVENUE DEFICIENCY (6 x 7)	29,947,305	35,982,693	40,006,389	73,158,638
9	ADJUSTED OPERATING REVENUES	1,089,881,400	1,039,007,300	1,047,346,862	1,054,394,438
10	REVENUE REQUIREMENTS (8 + 9)	1,119,828,705	1,074,989,993	1,087,353,251	1,127,553,075

(a) 13 months average

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2014-00372
OVERALL FINANCIAL SUMMARY
FORECAST PERIOD FOR THE 12 MONTHS ENDED DECEMBER 31,

		FORECASTED			
		2014	2015	2016	2017
LINE NO.	DESCRIPTION	JURISDICTIONAL REVENUE REQUIREMENT	JURISDICTIONAL REVENUE REQUIREMENT	JURISDICTIONAL REVENUE REQUIREMENT	JURISDICTIONAL REVENUE REQUIREMENT
		$	$	$	$
1	CAPITALIZATION ALLOCATED TO ELECTRIC OPERATIONS (a)	480,973,223	506,785,694	530,532,152	539,234,100
2	ADJUSTED OPERATING INCOME	34,776,141	30,520,373	30,236,118	28,458,170
3	EARNED RATE OF RETURN (2 / 1)	7.23%	6.02%	5.70%	5.28%
4	REQUIRED RATE OF RETURN	7.27%	7.24%	7.55%	7.65%
5	REQUIRED OPERATING INCOME (1 x 4)	34,971,885	36,666,799	40,051,983	41,272,547
6	OPERATING INCOME DEFICIENCY (5 - 2)	195,744	6,146,425	9,815,865	12,814,377
7	GROSS REVENUE CONVERSION FACTOR	1.608581	1.608581	1.608581	1.608581
8	REVENUE DEFICIENCY (6 x 7)	314,869	9,887,021	15,789,611	20,612,959
9	ADJUSTED OPERATING REVENUES	152,491,483	149,896,663	149,653,650	149,253,692
10	REVENUE REQUIREMENTS (8 + 9)	152,806,353	159,783,683	165,443,261	169,866,651

(a) 13 months average

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(5)
Sponsoring Witnesses: David S. Sinclair
Page 1 of 2

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:

LG&E Energy (GWh)

Rate	2015	2016	2017
PS-Pri (Commercial)	150	149	148
PS-Sec (Commercial)	1,730	1,728	1,724
CTOD-Pri	374	372	369
TOD-Sec (Commercial)	782	781	812
Special Contract 1	110	110	110
GS	1,385	1,386	1,388
PS-Pri (Industrial)	13	13	14
PS-Sec (Industrial)	246	230	226
ITOD-Pri	1,644	1,698	1,732
TOD-Sec (Industrial)	248	270	276
Lighting	123	123	123
Special Contract 2	58	58	58
RS	4,251	4,290	4,349
RTS	864	881	884
Total	11,978	12,090	12,211

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(5)
Sponsoring Witnesses: David S. Sinclair

LG&E Demand (Sum of Monthly Billing Demands)

Rate	SubRate	Unit	2015	2016	2017
PS-Pri (Commercial)	Base	MW	365	362	359
PS-Sec (Commercial)	Base	MW	4,296	4,290	4,281
CTOD-Pri	Base	MVA	890	884	877
	Intermediate	MVA	825	819	813
	Peak	MVA	807	801	795
TOD-Sec (Commercial)	Base	MW	1,717	1,714	1,783
	Intermediate	MW	1,626	1,624	1,688
	Peak	MW	1,596	1,594	1,657
Special Contract 1	Base	MW	160	160	160
PS-Pri (Industrial)	Base	MW	47	49	50
PS-Sec (Industrial)	Base	MW	771	723	710
ITOD-Pri	Base	MVA	4,038	4,171	4,254
	Intermediate	MVA	3,666	3,787	3,862
	Peak	MVA	3,617	3,736	3,811
TOD-Sec (Industrial)	Base	MW	619	675	689
	Intermediate	MW	577	629	642
	Peak	MW	561	612	625
Special Contract 2	Base	MW	113	113	113
RTS	Base	MVA	1,887	1,926	1,933
	Intermediate	MVA	1,816	1,853	1,859
	Peak	MVA	1,140	1,163	1,167

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(6)
Sponsoring Witnesses: Edwin R. Staton

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 LG&E's Application**.**

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(7)
Sponsoring Witnesses: 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.

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(h)(7)
Page 1 of 1
Sinclair

GWh	**2015**	**2016**	**2017**
Coal			
Brown 1	NA	NA	NA
Brown 2	NA	NA	NA
Brown 3	NA	NA	NA
Cane Run 4	174	0	0
Cane Run 5	242	0	0
Cane Run 6	0	0	0
Ghent 1	NA	NA	NA
Ghent 2	NA	NA	NA
Ghent 3	NA	NA	NA
Ghent 4	NA	NA	NA
Green River 3	NA	NA	NA
Green River 4	NA	NA	NA
Mill Creek 1	1,727	2,066	1,891
Mill Creek 2	1,693	1,927	1,965
Mill Creek 3	2,620	2,164	2,365
Mill Creek 4	2,730	2,819	2,934
OVEC	616	551	601
Trimble County 1	2,184	2,416	2,113
Trimble County 2	744	724	758
SCCT			
Brown 5	2	2	3
Brown 6	16	24	14
Brown 7	33	35	32
Brown 8	NA	NA	NA
Brown 9	NA	NA	NA
Brown 10	NA	NA	NA
Brown 11	NA	NA	NA
Cane Run 11	0	0	0
Haefling	NA	NA	NA
LS Power PPA	62	62	84
Paddys Run 11	0	0	0
Paddys Run 12	0	0	0
Paddys Run 13	37	84	77
Trimble County 5	85	68	63
Trimble County 6	72	47	58
Trimble County 7	73	61	63
Trimble County 8	16	14	12
Trimble County 9	58	46	50
Trimble County 10	10	10	13
Zorn	0	0	0
NGCC			
Cane Run 7	682	895	932
Hydro			
Dix Dam	NA	NA	NA
Ohio Falls	245	245	283
Total Coal	12,730	12,667	12,627
Total SCCT	464	453	470
Total NGCC	682	895	932
Total Hydro	245	245	283
Grand Total	14,121	14,260	14,311

Note: The generation volumes above are from LG&E’s ownership share of the unit. “NA” is shown for units with no LG&E ownership share.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(8)
Sponsoring Witnesses: J. Clay Murphy

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:

LOUISVILLE GAS AND ELECTRIC COMPANY			
MIX OF GAS SUPPLY			
CALENDAR YEARS 2015, 2016, 2017			
MMcf	**2015**	**2016**	**2017**
Total Pipeline Purchases	34,035	33,904	33,747

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(9)
Sponsoring Witnesses: Kent W. Blake

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.

Louisville Gas and Electric Company
Case No. 2014-00371
Employee Level
Years 2014-2017

	Estimated Number of Full-Time Employees at 12/31
2014	1721
2015	1730
2016	1742
2017	1745

	Estimated Number of Total Employees at 12/31
2014	1765
2015	1770
2016	1782
2017	1786

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(h)9

K. Blake

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(10)
Sponsoring Witnesses: Kent W. Blake

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.

Louisville Gas and Electric Company
Case No. 2014-00371
Labor Cost
Years 2014-2017

Forecast Year	Total Wages	Amount Over Previous Year	Percentage Over Previous Year
2014	$ 159,363,350		
2015	$ 161,081,184	$ 1,717,834	1.08%
2016	$ 159,632,392	$ (1,448,792)	-0.90%
2017	$ 163,167,435	$ 3,535,043	2.21%

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(h)10

K. Blake

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(11)
Sponsoring Witnesses: Kent W. Blake

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.

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2014-00372
ELECTRIC - CAPITAL STRUCTURE REQUIREMENT
AS OF
DECEMBER 31

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(h)(11)
Page 1 of 2
K. Blake

		FORECASTED							
		2014		2015		2016		2017	
LINE NO.	CLASS OF CAPITAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		$		$		$		$	
	ELECTRIC:								
1	SHORT-TERM DEBT	143,185,641	6.81%	64,792,723	3.01%	126,245,322	5.59%	39,695,127	1.62%
2	LONG-TERM DEBT	835,689,438	39.74%	936,776,863	43.58%	927,183,354	41.02%	1,102,323,371	45.10%
3	COMMON EQUITY	1,124,032,061	53.45%	1,147,949,155	53.40%	1,206,750,086	53.39%	1,301,922,183	53.27%
4	TOTAL CAPITAL	2,102,907,140	100.00%	2,149,518,741	100.00%	2,260,178,762	100.00%	2,443,940,681	100.00%

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2014-00372
GAS - CAPITAL STRUCTURE REQUIREMENT
AS OF
DECEMBER 31

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(h)(11)
Page 2 of 2
K. Blake

		FORECASTED							
		2014		2015		2016		2017	
LINE NO.	CLASS OF CAPITAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL	JURISDICTIONAL ADJUSTED	PERCENT OF TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		$		$		$		$	
	GAS:								
1	SHORT-TERM DEBT	34,646,586	6.81%	15,933,610	3.01%	30,481,063	5.59%	9,084,961	1.62%
2	LONG-TERM DEBT	202,211,518	39.74%	230,369,040	43.58%	223,862,035	41.02%	252,287,004	45.10%
3	COMMON EQUITY	271,981,694	53.45%	282,299,826	53.40%	291,361,497	53.39%	297,968,868	53.27%
4	TOTAL CAPITAL	508,839,797	100.00%	528,602,476	100.00%	545,704,596	100.00%	559,340,833	100.00%

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(12)
Sponsoring Witnesses: Kent W. Blake

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.

LOUISVILLE GAS AND ELECTRIC COMPANY

Electric - Net Original Cost Rate Base as of December 31

	Forecasted			
Title of Account (1)	2014 (2)	2015 (3)	2016 (3)	2017 (4)
1. Utility Plant at Original Cost	$ 4,466,667,114	$ 4,264,701,280	$ 4,402,458,968	$ 4,704,886,053
2. Deduct:				
3. Reserve for Depreciation	2,010,698,567	1,718,926,873	1,709,679,048	1,807,324,677
4. Net Utility Plant	2,455,968,547	2,545,774,407	2,692,779,920	2,897,561,376
5. Deduct:				
6. Customer Advances for Construction	1,468,097	1,631,544	1,631,544	1,631,544
7. Accumulated Deferred Income Taxes	441,582,686	458,964,668	491,708,602	512,847,562
8. Total Deductions	443,050,783	460,596,211	493,340,146	514,479,105
9. Net Plant Deductions	2,012,917,764	2,085,178,196	2,199,439,775	2,383,082,270
10. Add:				
11. Material and Supplies	93,315,698	83,125,412	75,706,723	77,564,105
12. Gas Stored Underground	-	-	-	-
13. Prepayments	5,076,367	4,611,239	5,949,718	5,611,833
14. Cash Working Capital (page 2)	90,243,948	83,243,773	80,509,553	84,319,932
15. Total Additions	188,636,013	170,980,424	162,165,994	167,495,870
16. Total Net Original Cost Rate Base	$ 2,201,553,776	$ 2,256,158,619	$ 2,361,605,769	$ 2,550,578,140

LOUISVILLE GAS AND ELECTRIC COMPANY

Electric - Calculation of Cash Working Capital
As of December 31

Title of Account (1)	Forecasted 2014 (2)	2015 (3)	2016 (3)	2017 (4)
1. Operating and maintenance expense for the 12 months ended December 31	$ 769,712,413	$ 726,880,263	$ 709,328,535	$ 743,606,201
2. Deduct:				
3. Electric Power Purchased	47,760,829	60,930,081	65,252,110	69,046,744
4. Gas Supply Expenses				
5. Total Deductions	$ 47,760,829	$ 60,930,081	$ 65,252,110	$ 69,046,744
6. Remainder (Line 1 - Line 5)	$ 721,951,585	$ 665,950,182	$ 644,076,425	$ 674,559,458
7. Cash Working Capital (12 1/2% of Line 6)	$ 90,243,948	$ 83,243,773	$ 80,509,553	$ 84,319,932

LOUISVILLE GAS AND ELECTRIC COMPANY

Gas - Net Original Cost Rate Base as of December 31

		Forecasted			
	Title of Account (1)	2014 (2)	2015 (3)	2016 (4)	2017 (5)
1.	Utility Plant at Original Cost	$ 929,183,742	$ 958,855,444	$ 993,077,953	$ 1,023,294,535
2.	Deduct:				
3.	Reserve for Depreciation	315,436,918	339,185,530	364,599,659	390,714,101
4.	Net Utility Plant	613,746,824	619,669,914	628,478,293	632,580,434
5.	Deduct:				
6.	Customer Advances for Construction	5,807,910	6,209,847	6,209,847	6,209,847
7.	Accumulated Deferred Income Taxes	126,275,646	111,257,702	105,227,847	98,463,313
8.	Total Deductions	132,083,556	117,467,548	111,437,694	104,673,159
9.	Net Plant Deductions	481,663,268	502,202,365	517,040,599	527,907,274
10.	Add:				
11.	Material and Supplies	624,247	533,481	472,064	462,246
12.	Gas Stored Underground	35,965,136	34,454,643	34,546,783	36,007,957
13.	Prepayments	743,908	711,072	917,471	865,368
14.	Cash Working Capital (page 2)	8,704,226	9,633,284	10,254,818	11,748,856
15.	Total Additions	46,037,517	45,332,479	46,191,136	49,084,427
16.	Total Net Original Cost Rate Base	$ 527,700,785	$ 547,534,845	$ 563,231,735	$ 576,991,701

LOUISVILLE GAS AND ELECTRIC COMPANY

Gas - Calculation of Cash Working Capital
As of December 31

Title of Account (1)	Forecasted 2,014 (2)	Forecasted 2,015 (3)	Forecasted 2,016 (4)	Forecasted 2,017 (5)
1. Operating and maintenance expense for the 12 months ended December 31	$ 253,548,341	$ 243,702,236	$ 251,319,658	$ 268,912,485
2. Deduct:				
3. Electric Power Purchased				
4. Gas Supply Expenses	183,914,535	166,635,967	169,281,115	174,921,640
5. Total Deductions	$ 183,914,535	$ 166,635,967	$ 169,281,115	$ 174,921,640
6. Remainder (Line 1 - Line 5)	$ 69,633,806	$ 77,066,270	$ 82,038,542	$ 93,990,845
7. Cash Working Capital (12 1/2% of Line 6)	$ 8,704,226	$ 9,633,284	$ 10,254,818	$ 11,748,856

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(13)
Sponsoring Witnesses: Edwin R. Staton

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 LG&E's Application.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(14)
Sponsoring Witnesses: 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:

LG&E Natural Gas Average Number of Customers

Rate	2015	2016	2017
As-Available Gas Service, Commercial	3	3	3
As-Available Gas Service, Industrial	3	3	3
E.I. DuPont - Special Contract	1	1	1
Firm Commercial Gas Service	23,675	23,719	23,762
Firm Industrial Gas Service	250	254	255
Gas Special Contracts - LG&E	1	1	1
Gas Transport Service, FT Commercial	10	10	10
Gas Transport Service, FT Industrial	69	69	69
Gas Transport Service, Paddy's Run	1	1	1
Residential Gas Service	294,343	294,886	295,424
TS-2: Gas Trans/Firm Balancing (AAGS In)	2	2	2
TS-2: Gas Transport/Firm Balancing (IGS)	2	2	2
Grand Total	318,360	318,950	319,533

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(15)
Sponsoring Witnesses: 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:

15. Sales volume forecasts – cubic feet (gas);

Response:

LG&E Natural Gas Volumes Forecast (Mcf)

Rate	2015	2016	2017
As-Available Gas Service, Commercial	65,932	51,024	52,730
As-Available Gas Service, Industrial	170,622	212,891	249,557
E.I. DuPont - Special Contract	577,361	606,229	606,229
Firm Commercial Gas Service	10,445,148	10,428,318	10,364,749
Firm Industrial Gas Service	1,173,937	1,224,762	1,266,165
Gas Special Contracts - LG&E	377,601	355,697	370,118
Gas Transport Service, FT Commercial	573,246	572,496	571,702
Gas Transport Service, FT Industrial	10,933,692	11,000,102	10,989,068
Gas Transport Service, Paddy's Run	1,393,236	1,246,271	1,289,429
Residential Gas Service	20,084,832	19,907,756	19,720,604
TS-2: Gas Trans/Firm Balancing (AAGS In)	152,429	152,145	151,872
TS-2: Gas Transport/Firm Balancing (IGS)	137,050	137,015	136,961
Grand Total	46,085,085	45,894,707	45,769,184

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(16)
Sponsoring Witnesses: Edwin R. Staton

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 LG&E’s Application.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(h)(17)
Sponsoring Witnesses: Kent W. Blake

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 LG&E's Application.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(i)
Sponsoring Witness: Valerie L. Scott

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 LG&E is attached. The Federal Communications Commission has not conducted an audit of LG&E, and, therefore, no such audit reports exist.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. 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

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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

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[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

KU and LG&E

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.

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[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.

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[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.

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[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.

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[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.

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[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.

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[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

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[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.

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[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

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[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]

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[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,

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[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

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[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.

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[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

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[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.

Convenience Payments

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

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.

Corrective Action: 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.

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 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. Merger Costs

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.

Corrective Action 1: 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.

Corrective Action 2: 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.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(j)
Sponsoring Witness: Kent W. Blake

Description of Filing Requirement:

The prospectuses of the most recent stock or bond offerings.

Response:

See attached.

PROSPECTUS SUPPLEMENT
(To Prospectus dated March 28, 2012)

$250,000,000

LG&E
a PPL company

Louisville Gas and Electric Company

4.65% First Mortgage Bonds due 2043

Louisville Gas and Electric Company is offering its First Mortgage Bonds, 4.65% Series due 2043. Interest on the Bonds will be payable on May 15 and November 15 of each year, commencing May 15, 2014, and at maturity, as further described in this prospectus supplement. The Bonds will mature on November 15, 2043 unless redeemed on an earlier date. We may, at our option, redeem the Bonds, in whole at any time or in part from time to time, as described herein. See "Description of the Bonds—Redemption."

The Bonds will be our senior secured indebtedness and will rank equally with all of our other outstanding senior secured indebtedness from time to time outstanding under our 2010 mortgage indenture. See "Description of the Bonds—Security; Lien of the Mortgage" herein.

Investing in the Bonds involves certain risks. See "Risk Factors" on page S-5 of this prospectus supplement, on page 4 of the accompanying prospectus and beginning on page 22 of our Annual Report on Form 10-K for the year ended December 31, 2012.

These securities have not been approved or disapproved by the Securities and Exchange Commission or any state securities commission, nor has the Securities and Exchange Commission or any state securities commission determined that this prospectus supplement or the accompanying prospectus is accurate or complete. Any representation to the contrary is a criminal offense.

	Price to Public(1)	Underwriting Discount	Proceeds, Before Expenses, to Us(1)
Per Bond	99.280%	0.875%	98.405%
Total	$248,200,000	$2,187,500	$246,012,500

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(1) Plus accrued interest, if any, from November 14, 2013.

The underwriters expect to deliver the Bonds to the purchasers in book-entry form through the facilities of The Depository Trust Company on or about November 14, 2013.

Joint Book-Running Managers

Citigroup RBS SunTrust Robinson Humphrey US Bancorp

Co-Managers

BBVA BNY Mellon Capital Markets, LLC Mizuho Securities PNC Capital Markets LLC

The date of this prospectus supplement is November 6, 2013.

We have not, and the underwriters have not, authorized anyone to provide any information other than that contained in or incorporated by reference into this prospectus supplement, the accompanying prospectus or any free writing prospectus prepared by or on behalf of us or to which we have referred you. We and the underwriters take no responsibility for, and can provide no assurance as to the reliability of, any other information that others may give you. We are not making an offer of these securities in any jurisdiction where the offer is not permitted. You should assume that the information contained in or incorporated by reference into this prospectus supplement, the accompanying prospectus or any free writing prospectus prepared by or on behalf of us or to which we have referred you is accurate only as of the respective date of such document. Our business, financial condition, results of operations and prospects may have changed since those dates.

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Prospectus Supplement

Prospectus

As used in this prospectus supplement and the accompanying prospectus, the terms “we,” “our” and “us” refer to Louisville Gas and Electric Company.

ABOUT THIS PROSPECTUS SUPPLEMENT

This prospectus supplement is part of a registration statement that Louisville Gas and Electric Company ("LG&E" or the "Company") has filed with the Securities and Exchange Commission (the "SEC") utilizing a "shelf" registration process. Under this shelf process, we are offering to sell the Bonds using this prospectus supplement and the accompanying prospectus. This prospectus supplement describes the specific terms of this offering. The accompanying prospectus and the information incorporated by reference therein and herein describe our business and give more general information, some of which may not apply to this offering. Generally, when we refer only to the "prospectus," we are referring to both parts combined. You should read this prospectus supplement together with the accompanying prospectus before making a decision to invest in the Bonds. If the information in this prospectus supplement or the information incorporated by reference in this prospectus supplement is inconsistent with the accompanying prospectus, the information in this prospectus supplement or the information incorporated by reference in this prospectus supplement will apply and will supersede that information in the accompanying prospectus.

Certain affiliates of LG&E, including PPL Corporation, LG&E and KU Energy LLC, Kentucky Utilities Company and other subsidiaries of PPL Corporation, have also registered their securities on the "shelf" registration statement referred to above. However, the Bonds are solely obligations of LG&E, and not of PPL Corporation or any of PPL Corporation's other subsidiaries or of any other affiliate of LG&E. None of PPL Corporation or any of LG&E's other affiliates will guarantee or provide any credit support for the Bonds.

WHERE YOU CAN FIND MORE INFORMATION

Available Information

LG&E files reports and other information with the SEC. You may obtain copies of this information by mail from the Public Reference Room of the SEC, 100 F Street, N.E., Room 1580, Washington, D.C. 20549, at prescribed rates. Further information on the operation of the SEC's Public Reference Room in Washington, D.C. can be obtained by calling the SEC at 1-800-SEC-0330.

LG&E's Internet Web site is http://www.lge-ku.com/lge/. Our ultimate parent, PPL Corporation, maintains an Internet Web site at www.pplweb.com. On the Investor Center page of that Web site, PPL Corporation provides access to SEC filings of LG&E free of charge, as soon as reasonably practicable after filing with the SEC. Neither the information at LG&E's Web site nor the information at PPL Corporation's Web site is incorporated in this prospectus supplement by reference, and you should not consider it a part of this prospectus supplement. LG&E's filings are also available at the SEC's Web site (www.sec.gov).

In addition, reports and other information concerning LG&E can be inspected at its offices at 220 West Main Street, Louisville, Kentucky 40202.

Incorporation by Reference

LG&E will "incorporate by reference" information into this prospectus supplement by disclosing important information to you by referring you to other documents that it files separately with the SEC. The information incorporated by reference is deemed to be part of this prospectus supplement, and later information that we file with the SEC will automatically update and supersede that information.

This prospectus supplement incorporates by reference the documents set forth below that have been previously filed with the SEC. These documents contain important information about LG&E.

SEC Filings	Period/Date
Annual Report on Form 10-K	Year ended December 31, 2012
Quarterly Reports on Form 10-Q	Quarters ended March 31, 2013, June 30, 2013 and September 30, 2013
Current Report on Form 8-K	Filed on October 3, 2013

Additional documents that LG&E files with the SEC pursuant to Section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), between the date of this prospectus supplement and the termination of the offering of the Bonds are also incorporated herein by reference.

LG&E will provide without charge to each person, including any beneficial owner, to whom a copy of this prospectus supplement has been delivered, a copy of any and all of its filings with the SEC. You may request a copy of these filings by writing or telephoning LG&E at:

Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Attention: Treasurer
Telephone: (502) 627-2000

SUMMARY

The following summary contains information about the offering by LG&E of its Bonds described below. It does not contain all of the information that may be important to you in making a decision to purchase the Bonds. For a more complete understanding of LG&E and the offering of the Bonds, we urge you to read this entire prospectus supplement, the accompanying prospectus and the documents incorporated by reference herein carefully including the "Risk Factors" sections and our financial statements and the notes to those statements.

The Issuer	Louisville Gas and Electric Company
Securities Offered	$250,000,000 aggregate principal amount of LG&E's First Mortgage Bonds, 4.65% Series due 2043 ("Bonds")
Stated Maturity Date	November 15, 2043
Interest Payment Dates	Interest on the Bonds will be payable on May 15 and November 15 of each year, commencing on May 15, 2014 and at maturity, or upon earlier redemption.
Interest Rate	4.65% per annum
Redemption	The Bonds may be redeemed at our option, in whole at any time or in part from time to time, at the redemption prices set forth in this prospectus supplement. The Bonds will not be entitled to the benefit of any sinking fund or other mandatory redemption and will not be repayable at the option of the Holder of a Bond prior to the Stated Maturity Date. See "Description of the Bonds—Redemption."
Ranking	The Bonds will be our senior secured indebtedness and will rank equally in right of payment with our existing and future first mortgage bonds issued under our Mortgage. See "Description of the Bonds—General" and "Description of the Bonds—Security; Lien of the Mortgage."
Security	The Bonds will be secured, equally and ratably, by the lien of the Mortgage, which constitutes a first mortgage lien on substantially all of our real and tangible personal property located in Kentucky and used in the generation, transmission and distribution of electricity and the storage, transportation and distribution of natural gas, other than property duly released from the lien of the Mortgage in accordance with the provisions thereof and certain other excepted property, and subject to certain Permitted Liens, as described under "Description of the Bonds—Security; Lien of the Mortgage."
Listing	We do not intend to list the Bonds on any securities exchange.
Form and Denomination	The Bonds will be initially issued in the form of one or more global securities, without coupons, in denominations of $2,000 and integral multiples of $1,000 in excess thereof, and deposited with the Trustee (as hereinafter defined) on behalf of The Depository Trust Company ("DTC"), as depositary, and registered in the name of DTC or its nominee. See "Description of the Bonds—General" and "Description of the Bonds—Book-Entry Only Issuance—The Depository Trust Company."

Use of Proceeds	We intend to use the net proceeds of this offering for the repayment of short-term debt obligations, including commercial paper borrowings, which as of September 30, 2013 had an average interest rate of approximately 0.28% and maturities under 30 days, for capital expenditures and for other general corporate purposes. See "Use of Proceeds."
Reopening of the Series	We may, without the consent of the Holders of the Bonds, increase the principal amount of the series and issue additional bonds of such series having the same ranking, interest rate, maturity and other terms as the Bonds, other than the date of initial issuance, the price to public, and, in some circumstances, the initial interest accrual date and the initial interest payment date. Any such additional bonds may, together with the Bonds, constitute a single series of securities under the Mortgage. See "Description of the Bonds—General."
Governing Law	The Bonds and the Mortgage are governed by the laws of the State of New York, except to the extent the Trust Indenture Act of 1939, as amended (the "Trust Indenture Act") is applicable and except where otherwise required by law. The effectiveness of the lien of the Mortgage, and the perfection and priority thereof, will be governed by Kentucky law.

RISK FACTORS

Before making a decision to invest in the Bonds, you should carefully consider the risk factors described below, the risk factors described on page 4 of the accompanying prospectus, and the risk factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2012, beginning on page 22, as well as the other information included in this prospectus supplement, the accompanying prospectus and the documents incorporated by reference in this prospectus supplement and the accompanying prospectus.

Risks Relating to the Bonds

An active trading market for the Bonds may not develop.

The Bonds are new securities and we do not intend to apply for listing of the Bonds on any securities exchange. We cannot assure that an active trading market for the Bonds will develop. There can be no assurances as to the liquidity of any market that may develop for the Bonds, the ability of Holders to sell their Bonds or the price at which the Holders will be able to sell their Bonds. Future trading prices of the Bonds will depend on many factors including, among other things, prevailing interest rates, our operating results and the market for similar securities.

USE OF PROCEEDS

We intend to use the net proceeds of this offering for the repayment of short-term debt, including commercial paper borrowings, which as of September 30, 2013 had an average interest rate of approximately 0.28% and maturities under 30 days, for capital expenditures and for other general corporate purposes.

CAPITALIZATION

The following table sets forth our consolidated capitalization as of September 30, 2013 on an actual basis, and on an as adjusted basis to give effect to the issuance of the Bonds in this offering and the use of proceeds of this offering for the repayment of short-term debt. This table should be read in conjunction with our consolidated financial statements, the notes related thereto and the financial and operating data incorporated by reference into this prospectus supplement and the accompanying prospectus.

	As of September 30, 2013	
	Actual	**As Adjusted**
	(In millions)	
Short-term debt	72	0
Capitalization		
Long-term debt	1,112	1,112
Bonds offered hereby	—	250
Total long-term debt	1,112	1,362
Total stockholder's equity	1,919	1,919
Total capitalization	$3,031	$3,281

DESCRIPTION OF THE BONDS

The following summary description sets forth certain terms and provisions of the Bonds that we are offering by this prospectus supplement. Because this description is a summary, it does not describe every aspect of the Bonds or the Mortgage (as defined below) under which the Bonds will be issued, as described below. The Mortgage is filed as an exhibit to the registration statement of which the accompanying prospectus is a part. The Mortgage and its associated documents contain the full legal text of the matters described in this section. This summary is subject to and qualified in its entirety by reference to all of the provisions of the Bonds and the Mortgage, including definitions of certain terms used in the Mortgage. We also include references in parentheses to certain sections of the Mortgage. Whenever we refer to particular sections or defined terms of the Mortgage in this prospectus supplement, such sections or defined terms are incorporated by reference herein. The Mortgage has been qualified under the Trust Indenture Act, and you should refer to the Trust Indenture Act for provisions that apply to the Bonds.

General

We will issue the Bonds as a series of debt securities under our indenture, dated as of October 1, 2010 (as such indenture has been and may be amended and supplemented from time to time, the "Mortgage"), with The Bank of New York Mellon, as trustee (the "Trustee"). The Mortgage does not effectively limit the aggregate principal amount of bonds or other debt securities that may be issued thereunder, subject to meeting certain conditions to issuance, including those described below under "Issuance of Additional Mortgage Securities." The Bonds and all other debt securities issued previously or hereafter issued under the Mortgage are collectively referred to herein as "Mortgage Securities." The Mortgage constitutes a first mortgage lien, subject to Permitted Liens and exceptions and exclusions as described below, on substantially all of our real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity and the storage, transportation and distribution of natural gas. (See "—Security; Lien of the Mortgage" below.) As of the date of this prospectus supplement, approximately $1.109 billion of first mortgage bonds are issued and outstanding under the Mortgage, including $574 million which have been pledged to secure pollution control revenue bonds issued by various counties in Kentucky on our behalf.

The Bonds will be issued in fully registered form only, without coupons. The Bonds will be initially represented by one or more fully registered global securities (the "Global Securities") deposited with the Trustee, as custodian for The Depository Trust Company ("DTC"), as depositary, and registered in the name of DTC or DTC's nominee. A beneficial interest in a Global Security will be shown on, and transfers or exchanges thereof will be effected only through, records maintained by DTC and its participants, as described below under "—Book-Entry Only Issuance—The Depository Trust Company." The authorized denominations of the Bonds will be $2,000 and integral multiples of $1,000 in excess thereof. Except in limited circumstances described below, the Bonds will not be exchangeable for Bonds in definitive certificated form.

The Bonds are initially being offered in one series in the principal amount of $250,000,000. We may, without the consent of the Holders of the Bonds, increase the principal amount of the series and issue additional bonds of such series having the same ranking, interest rate, maturity and other terms (other than the date of initial issuance, the price to public and, in some circumstances, the initial interest accrual date and initial interest payment date) as the Bonds, but we will not reopen a series unless the additional bonds are fungible with the previously issued bonds for U.S. federal income tax purposes or such additional bonds are issued with a separate CUSIP number. Any such additional bonds would, together with the Bonds, constitute a single series of securities under the Mortgage and may be treated as a single class for all purposes under the Mortgage, including, without limitation, voting waivers and amendments.

Maturity; Interest

The Bonds will mature on November 15, 2043 (the "Stated Maturity Date") and will bear interest from the date of issuance at a rate of 4.65% per annum. Interest will be payable on the Bonds on May 15 and November 15 of each year (each, an "Interest Payment Date"), commencing on May 15, 2014, and at maturity (whether at the Stated Maturity Date, upon redemption or acceleration, or otherwise, "Maturity"). Subject to certain exceptions, the Mortgage provides for the payment of interest on an Interest Payment Date only to persons in whose names the Bonds are registered at the close of business on the Regular Record Date, which will be the May 1 and November 1 (whether or not a Business Day), as the case may be, immediately preceding the applicable Interest Payment Date; except that interest payable at Maturity will be paid to the person to whom principal is paid.

Interest on the Bonds will be calculated on the basis of a 360-day year of twelve 30-day months, and with respect to any period less than a full calendar month, on the basis of the actual number of days elapsed during the period.

Payment

So long as the Bonds are registered in the name of DTC, as depositary for the Bonds as described herein under "—Book-Entry Only Issuance—The Depository Trust Company" or DTC's nominee, payments on the Bonds will be made as described therein.

If we default in paying interest on a Bond, we will pay such defaulted interest either

- to Holders as of a special record date between 10 and 15 days before the proposed payment; or
- in any other lawful manner of payment that is consistent with the requirements of any securities exchange on which the Bonds may be listed for trading. (See Section 307.)

We will pay principal of and interest and premium, if any, on the Bonds at Maturity upon presentation of the Bonds at the corporate trust office of The Bank of New York Mellon in New York, New York, as our Paying Agent. In our discretion, we may change the place of payment on the Bonds, and we may remove any Paying Agent and may appoint one or more additional Paying Agents (including us or any of our affiliates). (See Section 702.)

If any Interest Payment Date, Redemption Date or Maturity of a Bond falls on a day that is not a Business Day, the required payment of principal, premium, if any, and/or interest will be made on the next succeeding Business Day as if made on the date such payment was due, and no interest will accrue on such payment for the period from and after such Interest Payment Date, Redemption Date or Maturity, as the case may be, to the date of such payment on the next succeeding Business Day.

"Business Day" means any day, other than a Saturday or Sunday, that is not a day on which banking institutions or trust companies in The City of New York, New York, or other city in which a paying agent for such Bond is located, are generally authorized or required by law, regulation or executive order to remain closed. (See Section 116.)

Form; Transfers; Exchanges

So long as the Bonds are registered in the name of DTC, as depositary for the Bonds as described herein under "—Book-Entry Only Issuance—The Depository Trust Company" or DTC's nominee, transfers and exchanges of beneficial interest in the Bonds will be made as described therein. In the event that the book-entry only system is discontinued, and the Bonds are issued in certificated form, you may exchange or transfer Bonds at the corporate trust office of the Trustee.

You may have your Bonds divided into Bonds of smaller denominations (of at least $2,000 and any larger amount that is an integral multiple of $1,000) or combined into Bonds of larger denominations, as long as the total principal amount is not changed. (See Section 305.)

There will be no service charge for any transfer or exchange of the Bonds, but you may be required to pay a sum sufficient to cover any tax or other governmental charge payable in connection therewith. We may block the transfer or exchange of (1) Bonds during a period of 15 days prior to giving any notice of redemption or (2) any Bond selected for redemption in whole or in part, except the unredeemed portion of any Bond being redeemed in part. (See Section 305.)

The Trustee acts as our agent for registering Bonds in the names of Holders and transferring the Bonds. We may appoint another agent (including one of our affiliates) or act as our own agent for this purpose. The entity performing the role of maintaining the list of registered Holders is called the "Security Registrar." It will also perform transfers. In our discretion, we may change the place for registration of transfer of the Bonds and may designate a different entity as the Security Registrar, including us or one of our affiliates. (See Sections 305 and 702.)

Redemption

We may, at our option, redeem the Bonds, in whole at any time or in part from time to time. If we redeem the Bonds before May 15, 2043 (the date that is six months prior to the Stated Maturity Date), the Bonds will be redeemed by us at a redemption price equal to the greater of:

- 100% of the principal amount of the Bonds to be so redeemed; and
- as determined by the Quotation Agent, the sum of the present values of the remaining scheduled payments of principal and interest on the Bonds to be so redeemed (not including any portion of such payments of interest accrued to the date of redemption) discounted to the Redemption Date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Adjusted Treasury Rate, plus 15 basis points;

plus, in either case, accrued and unpaid interest on the principal amount of Bonds to be so redeemed to the Redemption Date.

If we redeem the Bonds on or after May 15, 2043, the Bonds will be redeemed by us at a redemption price equal to 100% of the principal amount of the Bonds to be so redeemed, plus accrued and unpaid interest on the principal amount of the Bonds to be so redeemed to the Redemption Date.

"Adjusted Treasury Rate" means, with respect to any Redemption Date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for that Redemption Date.

"Comparable Treasury Issue" means the United States Treasury security selected by the Quotation Agent as having an actual or interpolated maturity comparable to the remaining term of the Bonds to be redeemed to the Stated Maturity Date that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the Bonds being redeemed.

"Comparable Treasury Price" means, with respect to any Redemption Date:

- the average of five Reference Treasury Dealer Quotations for that Redemption Date, after excluding the highest and lowest Reference Treasury Dealer Quotations; or
- if the Quotation Agent obtains fewer than five Reference Treasury Dealer Quotations, the average of all of those quotations received.

"Quotation Agent" means one of the Reference Treasury Dealers appointed by us.

"*Reference Treasury Dealer*" means:

- each of Citigroup Global Markets Inc. and RBS Securities Inc. (or their respective affiliates that are Primary Treasury Dealers, as defined below), a Primary Treasury Dealer selected by SunTrust Robinson Humphrey, Inc. and a Primary Treasury Dealer selected by U.S. Bancorp Investments, Inc., or their respective successors, unless any of them ceases to be a primary U.S. Government securities dealer in the United States (a "Primary Treasury Dealer"), in which case we will substitute another Primary Treasury Dealer; and
- any other Primary Treasury Dealer selected by us (after consultation with the Quotation Agent).

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any Redemption Date, the average, as determined by the Quotation Agent, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount), as provided to the Quotation Agent by that Reference Treasury Dealer at 5:00 p.m., New York City time, on the third Business Day preceding that Redemption Date.

The Bonds will not be subject to a sinking fund or other mandatory redemption provisions and will not be repayable at the option of the Holder prior to the Stated Maturity Date.

The Bonds will be redeemable upon notice of redemption to each holder of Bonds to be redeemed by mail between 30 days and 60 days prior to the Redemption Date.

If less than all of the Bonds are to be redeemed, the Trustee will select the Bonds or portions thereof to be redeemed. In the absence of any provision for selection, the Trustee will choose a method of random selection that it deems fair and appropriate. (See Sections 503 and 504.)

We may make any redemption at our option conditional upon the receipt by the Paying Agent, on or prior to the date fixed for redemption, of money sufficient to pay the redemption price. If the Paying Agent has not received such money by the date fixed for redemption, we will not be required to redeem such Bonds. (See Section 504.)

Bonds called for redemption will cease to bear interest on the Redemption Date. We will pay the redemption price and any accrued interest once you surrender the Bond for redemption. (See Section 505.) If only part of a Bond is redeemed, the Trustee will deliver to you a new Bond of the same series for the remaining portion without charge. (See Section 506.)

Security; Lien of the Mortgage

General

Except as described below under this heading and under "—Issuance of Additional Mortgage Securities," and subject to the exceptions described under "—Satisfaction and Discharge," all Mortgage Securities, including the Bonds, will be secured, equally and ratably, by the lien of the Mortgage, which constitutes, subject to Permitted Liens as described below, a first mortgage lien on substantially all of our real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity and the storage, transportation and distribution of natural gas (other than property duly released from the lien of the Mortgage in accordance with the provisions thereof and other than Excepted Property, as described below). We sometimes refer to our property that is subject to the lien of the Mortgage as "Mortgaged Property."

We may obtain the release of property from the lien of the Mortgage from time to time, upon the bases provided for such release in the Mortgage. See "—Release of Property."

We may enter into supplemental indentures with the Trustee, without the consent of the Holders, in order to subject additional property (including property that would otherwise be excepted from such lien) to the lien of the Mortgage. (See Section 1401.) This property would constitute Property Additions and would be available as a basis for the issuance of Mortgage Securities. See "—Issuance of Additional Mortgage Securities."

The Mortgage provides that after-acquired property (other than Excepted Property) will be subject to the lien of the Mortgage. (See Granting Clause Second.) However, in the case of consolidation or merger (whether or not we are the surviving company) or transfer of the Mortgaged Property as or substantially as an entirety, the Mortgage 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 us in or as a result of such transfer, as well as improvements, extensions and additions (as defined in the Mortgage) to such properties and renewals, replacements and substitutions of or for any part or parts thereof. See Section 1303 and "—Consolidation, Merger and Conveyance of Assets as an Entirety."

Excepted Property. The lien of the Mortgage 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 Mortgage; property not used by us in our electric generation, transmission and distribution business or our gas storage, transportation and distribution business; cash and securities not paid, deposited or held under the Mortgage 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 our business; fuel; tools and equipment; furniture and furnishings; computers and data processing, telecommunications and other facilities used primarily for administrative or clerical purposes or otherwise not used in connection with the operation or maintenance of electric generation, transmission and distribution facilities or natural gas storage, transportation and distribution facilities; coal, ore, gas, oil and other minerals and timber rights; electric energy and capacity, gas, steam, water and other products generated, produced, manufactured, purchased or otherwise acquired; real property and facilities used primarily for the production or gathering of natural gas; property which has been released from the lien of the Mortgage; and leasehold interests. We sometimes refer to our property not covered by the lien of the Mortgage as "Excepted Property." (See Granting Clauses.) Properties held by any of our subsidiaries, as well as properties leased from others, would not be subject to the lien of the Mortgage.

Permitted Liens. The lien of the Mortgage is subject to Permitted Liens described in the Mortgage. Such Permitted Liens include liens existing at the execution date of the Mortgage, purchase money liens and other liens placed or otherwise existing on property acquired by us after the execution date of the Mortgage at the time we acquire 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, our 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 us or by others on our property, rights and interests of Persons other than us 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. (See Granting Clauses and Section 101.)

The Mortgage also provides that the Trustee will have a lien, prior to the lien on behalf of the Holders of the Mortgage Securities, upon the Mortgaged Property as security for our payment of its reasonable compensation and expenses and for indemnity against certain liabilities. (See Section 1107.) Any such lien would be a Permitted Lien under the Mortgage.

Issuance of Additional Mortgage Securities

The maximum principal amount of Mortgage Securities that may be authenticated and delivered under the Mortgage is subject to the issuance restrictions described below; provided, however, that the maximum principal amount of Mortgage Securities 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. (See Section 301.) Mortgage Securities of any series may be issued from time to time on the basis of, and in an aggregate principal amount not exceeding:

- 66⅔% 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 Mortgage Securities, 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 Trustee. (See Article Four.)

Property Additions generally include any property which is owned by us and is subject to the lien of the Mortgage 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 our operating expense accounts in accordance with U.S. generally accepted accounting principles. (See Section 104.)

Retired Securities means, generally, Mortgage Securities which are no longer outstanding under the Mortgage, 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 Mortgage Securities, the release of property or the withdrawal of cash.

We intend to issue the Bonds on the basis of Property Additions. At August 31, 2013 approximately $1.28 billion of Property Additions were available to us to be used as the basis for the authentication and delivery of Mortgage Securities (including the Bonds offered hereby). (See Article Four)

Release of Property

Unless an Event of Default has occurred and is continuing, we may obtain the release from the lien of the Mortgage of any Mortgaged Property, except for cash held by the Trustee, upon delivery to the Trustee of an amount in cash equal to the amount, if any, by which sixty-six and two-thirds percent (66⅔%) of the Cost of the property to be released (or, if less, the Fair Value to us of such property at the time it became Funded Property) exceeds the aggregate of:

- an amount equal to 66⅔% of the aggregate principal amount of obligations secured by Purchase Money Liens upon the property to be released and delivered to the Trustee;
- an amount equal to 66⅔% of the Cost or Fair Value to us (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 Mortgage Securities we 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 Mortgage Securities delivered to the Trustee (with such Mortgage Securities to be canceled by the Trustee);
- any amount of cash and/or an amount equal to 66⅔% 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 Mortgage, subject to certain limitations described in the Mortgage; and
- any taxes and expenses incidental to any sale, exchange, dedication or other disposition of the property to be released.

(See Section 803.)

As used in the Mortgage, 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 (See Section 101.).

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 Mortgage without depositing any cash or property with the Trustee as long as (a) the aggregate amount of Cost or Fair Value to us (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 us (whichever is less) of Property Additions acquired or made within the 90-day period preceding the release. (See Section 804.)

The Mortgage 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 Trustee. (See Sections 805, 807 and 808.)

If we retain any interest in any property released from the lien of the Mortgage, the Mortgage 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. (See Section 809.)

Withdrawal of Cash

Unless an Event of Default has occurred and is continuing, and subject to certain limitations, cash held by the Trustee may, generally, (1) be withdrawn by us (a) to the extent of sixty-six and two-thirds percent (66⅔%) of the Cost or Fair Value to us (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 Mortgage Securities that we 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 Mortgage Securities delivered to the Trustee; or (2) upon our request, be applied to (a) the purchase of Mortgage Securities in a manner and at a price approved by us or (b) the payment (or provision for payment) at stated maturity of any Mortgage Securities or the redemption (or provision for payment) of any Mortgage Securities which are redeemable (see Section 806); provided, however, that cash deposited with the Trustee as the basis for the authentication and delivery of Mortgage Securities may, in addition, be withdrawn in an amount not exceeding the aggregate principal amount of cash delivered to the Trustee for such purpose. (See Section 404.)

Events of Default

An "Event of Default" occurs under the Mortgage if

- we do not pay any interest on any Mortgage Securities within 30 days of the due date;
- we do not pay principal or premium, if any, on any Mortgage Securities on the due date;
- we remain in breach of any other covenant (excluding covenants specifically dealt with elsewhere in this section) in respect of any Mortgage Securities for 90 days after we receive a written notice of default stating we are in breach and requiring remedy of the breach; the notice must be sent by either the Trustee or Holders of 25% of the principal amount of outstanding Mortgage Securities; the 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 we initiate corrective action within such 90-day period and we are diligently pursuing such action to correct the default; or
- we file for bankruptcy or certain other events in bankruptcy, insolvency, receivership or reorganization occur.

(See Section 1001.)

Remedies

Acceleration of Maturity

If an Event of Default occurs and is continuing, then either the Trustee or the Holders of not less than 25% in principal amount of the outstanding Mortgage Securities may declare the principal amount of all of the Mortgage Securities to be due and payable immediately. (See Section 1002.)

Rescission of Acceleration

After the declaration of acceleration has been made and before the Trustee has obtained a judgment or decree for payment of the money due, such declaration and its consequences will be rescinded and annulled, if

(i) we pay or deposit with the 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 Trustee under the Mortgage; and

(ii) 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 Mortgage.

(See Section 1002.)

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 Mortgage, under certain circumstances and to the extent permitted by law, if an Event of Default occurs and is continuing, the 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. (See Section 1016.)

Control by Holders; Limitations

Subject to the Mortgage, if an Event of Default occurs and is continuing, the Holders of a majority in principal amount of the outstanding Mortgage Securities will have the right to

- direct the time, method and place of conducting any proceeding for any remedy available to the Trustee, or
- exercise any trust or power conferred on the 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 Mortgage; and
- the Holders' directions may not involve the Trustee in personal liability where the Trustee believes indemnity is not adequate.

The Trustee may also take any other action it deems proper which is not inconsistent with the Holders' direction. (See Sections 1012 and 1103.)

In addition, the Mortgage provides that no Holder of any Mortgage Security will have any right to institute any proceeding, judicial or otherwise, with respect to the Mortgage for the appointment of a receiver or for any other remedy thereunder unless

- that Holder has previously given the Trustee written notice of a continuing Event of Default;
- the Holders of 25% in aggregate principal amount of the outstanding Mortgage Securities have made written request to the Trustee to institute proceedings in respect of that Event of Default and have offered the 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 Trustee has failed to institute any such proceeding and no direction inconsistent with such request has been given to the Trustee during such 60-day period by the Holders of a majority in aggregate principal amount of outstanding Mortgage Securities.

Furthermore, no Holder 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. (See Sections 1007 and 1103.)

However, each Holder has an absolute and unconditional right to receive payment when due and to bring a suit to enforce that right. (See Section 1008.)

Notice of Default

The Trustee is required to give the Holders of the Mortgage Securities notice of any default under the Mortgage 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. (See Section 1102.) The Trust Indenture Act currently permits the Trustee to withhold notices of default (except for certain payment defaults) if the Trustee in good faith determines the withholding of such notice to be in the interests of the Holders.

We will furnish the Trustee with an annual statement as to our compliance with the conditions and covenants in the Mortgage. (See Section 709.)

Waiver of Default and of Compliance

The Holders of a majority in aggregate principal amount of the outstanding Mortgage Securities may waive, on behalf of the Holders of all outstanding Mortgage Securities, any past default under the Mortgage, except a default in the payment of principal, premium or interest, or with respect to compliance with certain provisions of the Mortgage that cannot be amended without the consent of the Holder of each outstanding Mortgage Security affected. (See Section 1013.)

Compliance with certain covenants in the Mortgage or otherwise provided with respect to Mortgage Securities may be waived by the Holders of a majority in aggregate principal amount of the affected Mortgage Securities, considered as one class. (See Section 710.)

Consolidation, Merger and Conveyance of Assets as an Entirety

Subject to the provisions described below, we have agreed to preserve our corporate existence. (See Section 704.)

We have 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 we merge, 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 Mortgage Securities and the performance of all of our covenants under the Mortgage; and
- such entity confirms the lien of the Mortgage on the Mortgaged Property; and
- in the case of a lease, such lease is made expressly subject to termination by (i) us or by the 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.

(See Section 1301.)

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 we would be released and discharged from all obligations under the Mortgage and on the Mortgage Securities then outstanding unless we elect to waive such release and discharge. (See Section 1304.)

The Mortgage does not prevent or restrict:

- any consolidation or merger after the consummation of which we 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 Mortgage Securities, 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 we select and that is approved by the Trustee.

(See Sections 1305 and 1306.)

Modification of Mortgage

Without Holder Consent. Without the consent of any Holders of Mortgage Securities, we and the Trustee may enter into one or more supplemental indentures for any of the following purposes:

- to evidence the succession of another entity to us;
- to add one or more covenants or other provisions for the benefit of the Holders of all or any series or tranche of Mortgage Securities, or to surrender any right or power conferred upon us;
- to correct or amplify the description of any property at any time subject to the lien of the Mortgage; or to better assure, convey and confirm unto the Trustee any property subject or required to be subjected to the lien of the Mortgage; or to subject to the lien of the Mortgage 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 Mortgage 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 Mortgage Securities of any one more particular series remains outstanding;
- to change or eliminate any provision of the Mortgage or to add any new provision to the Mortgage 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 Mortgage Securities;
- to provide for the issuance of bearer securities;
- to evidence and provide for the acceptance of appointment of a successor 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 Mortgage Securities;
- to change any place or places where
    - we may pay principal, premium and interest,
    - Mortgage Securities may be surrendered for transfer or exchange, and
    - notices and demands to or upon us may be served;
- to amend and restate the Mortgage 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 Mortgage Securities that may be outstanding at any time.

In addition, if the Trust Indenture Act is amended after the date of the Mortgage so as to require changes to the Mortgage or so as to permit changes to, or the elimination of, provisions which, at the date of the Mortgage or at any time thereafter, were required by the Trust Indenture Act to be contained in the Mortgage, the Mortgage will be deemed to have been amended so as to conform to such amendment or to effect such changes or elimination, and we and the Trustee may, without the consent of any Holders, enter into one or more supplemental indentures to effect or evidence such amendment.

(See Section 1401.)

With Holder Consent. Except as provided above, the consent of the Holders of at least a majority in aggregate principal amount of the Mortgage Securities 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 Mortgage pursuant to a supplemental indenture. However, if less than all of the series of outstanding Mortgage Securities 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 Mortgage Securities of all directly affected series, considered as one class. Moreover, if the Mortgage Securities 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 Mortgage Securities 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 Mortgage Securities of all directly affected tranches, considered as one class.

However, no amendment or modification may, without the consent of the Holder of each outstanding Mortgage Security directly affected thereby,

- change the stated maturity of the principal or interest on any Mortgage Security (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 Mortgage Security is payable, or impair the right to bring suit to enforce any payment;
- create any lien (not otherwise permitted by the Mortgage) ranking prior to the lien of the Mortgage with respect to all or substantially all of the Mortgaged Property, or terminate the lien of the Mortgage on all or substantially all of the Mortgaged Property (other than in accordance with the terms of the Mortgage), or deprive any Holder of the benefits of the security of the lien of the Mortgage;
- reduce the percentages of Holders whose consent is required for any supplemental indenture or waiver of compliance with any provision of the Mortgage or of any default thereunder and its consequences, or reduce the requirements for quorum and voting under the Mortgage; or
- modify certain of the provisions of the Mortgage relating to supplemental indentures, waivers of certain covenants and waivers of past defaults with respect to Mortgage Securities.

A supplemental indenture which changes, modifies or eliminates any provision of the Mortgage expressly included solely for the benefit of Holders of Mortgage Securities of one or more particular series or tranches will be deemed not to affect the rights under the Mortgage of the Holders of Mortgage Securities of any other series or tranche.

(See Section 1402.)

Satisfaction and Discharge

Any Mortgage Securities or any portion thereof will be deemed to have been paid and no longer outstanding for purposes of the Mortgage and, at our election, our entire indebtedness with respect to those securities will be satisfied and discharged, if there shall have been irrevocably deposited with the 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 Mortgage Securities, non-redeemable Eligible Obligations (as defined in the Mortgage) 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 Mortgage Securities or portions of such Mortgage Securities on and prior to their maturity.

(See Section 901.)

Our right to cause our entire indebtedness in respect of the Mortgage Securities 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 Mortgage will be deemed satisfied and discharged when no Mortgage Securities remain outstanding and when we have paid all other sums payable by us under the Mortgage. (See Section 902.)

All moneys we pay to the Trustee or any Paying Agent on Bonds that remain unclaimed at the end of two years after payments have become due may be paid to or upon our order. Thereafter, the Holder of such Bond may look only to us for payment. (See Section 703.)

Duties of the Trustee; Resignation and Removal of the Trustee; Deemed Resignation

The 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 Trustee will be under no obligation to exercise any of the powers vested in it by the Mortgage at the request of any holder of Mortgage Securities, unless offered reasonable indemnity by such holder against the costs, expenses and liabilities which might be incurred thereby. The 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 Trustee reasonably believes that repayment or adequate indemnity is not reasonably assured to it.

The Trustee may resign at any time by giving written notice to us.

The Trustee may also be removed by act of the Holders of a majority in principal amount of the then outstanding Mortgage Securities of any series.

No resignation or removal of the 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 Mortgage.

Under certain circumstances, we may appoint a successor trustee and if the successor accepts, the Trustee will be deemed to have resigned.

(See Section 1110.)

Evidence to be Furnished to the Trustee

Compliance with Mortgage provisions is evidenced by written statements of our officers or persons selected or paid by us. 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 Mortgage requires us to give to the Trustee, not less than annually, a brief statement as to our compliance with the conditions and covenants under the Mortgage.

Miscellaneous Provisions

The Mortgage provides that certain Mortgage Securities, 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 Mortgage Securities have given or taken any demand, direction, consent or other action under the Mortgage as of any date, or are present at a meeting of Holders for quorum purposes. (See Section 101.)

We will be entitled to set any day as a record date for the purpose of determining the Holders of outstanding Mortgage Securities of any series entitled to give or take any demand, direction, consent or other action under the Mortgage, in the manner and subject to the limitations provided in the Mortgage. In certain circumstances, the 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 Mortgage Securities, such action may be taken only by persons who are Holders of such Mortgage Securities on the record date. (See Section 107.)

Governing Law

The Mortgage and the Mortgage Securities 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. (See Section 115.) The effectiveness of the lien of the Mortgage, and the perfection and priority thereof, will be governed by Kentucky law.

Regarding the Trustee

The Trustee under the Mortgage is the Bank of New York Mellon ("BNYM"). In addition to acting as Trustee, BNYM also maintains various banking and trust relationships with us and some of our affiliates.

Book-Entry Only Issuance—The Depository Trust Company

DTC will act as the initial securities depositary for the Bonds. The Bonds will be issued as fully-registered securities 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. The global bonds will be deposited with the Trustee as custodian for 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 Exchange Act. DTC holds securities for its participants ("Direct Participants") and 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, thereby eliminating 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"). The rules that apply to DTC and those using its system 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 ("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 purchases, but Beneficial Owners should receive written confirmations providing details of the transactions, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which they purchased Bonds. Transfers of ownership interests on 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 Bonds, except in the event that use of the book-entry system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of the 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 the 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. Notices will be sent to DTC.

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 us as soon as possible after the record date. The omnibus proxy assigns the voting or consenting rights of Cede & Co. to those Direct Participants to whose accounts the Bonds are credited on the record date. We believe that these arrangements will enable the Beneficial Owners to exercise rights equivalent in substance to the rights that can be directly exercised by a registered Holder of the Bonds.

Payments of principal and interest on the Bonds will be made to Cede & Co. (or such other nominee of DTC). DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from us or the Trustee, on 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 and will be the responsibility of such participant and not of DTC, the Trustee or us, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment to Cede & Co. (or such other nominee of DTC) is the responsibility of us 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 is the responsibility of Direct and Indirect Participants.

A Beneficial Owner will not be entitled to receive physical delivery of the Bonds. Accordingly, each Beneficial Owner must rely on the procedures of DTC to exercise any rights under the Bonds.

DTC may discontinue providing its services as securities depositary with respect to the Bonds at any time by giving us or the Trustee reasonable notice. In the event no successor securities depositary is obtained, certificates for the Bonds will be printed and delivered.

The information in this section concerning DTC and DTC's book-entry system has been obtained from sources that we believe to be reliable, but neither we nor the underwriters take any responsibility for the accuracy of this information.

UNDERWRITING

LG&E and the underwriters have entered into an underwriting agreement with respect to the Bonds. Subject to certain conditions, each underwriter has severally, but not jointly, agreed to purchase the principal amount of Bonds indicated in the following table:

Underwriters	Principal Amount of Bonds
Citigroup Global Markets Inc.	$ 50,000,000
RBS Securities Inc.	50,000,000
SunTrust Robinson Humphrey, Inc.	50,000,000
U.S. Bancorp Investments, Inc.	50,000,000
BBVA Securities Inc.	12,500,000
BNY Mellon Capital Markets, LLC	12,500,000
Mizuho Securities USA Inc.	12,500,000
PNC Capital Markets LLC	12,500,000
Total	$250,000,000

The underwriters are committed to take and pay for all of the Bonds being offered, if any are taken.

Bonds sold by the underwriters to the public will initially be offered at the initial public offering price set forth on the cover of this prospectus supplement. Any Bonds sold by the underwriters to securities dealers may be sold at a discount from the initial public offering price of up to 0.50% of the principal amount of the Bonds. Any such securities dealers may resell any Bonds purchased from the underwriters to certain other brokers or dealers at a discount from the initial public offering price of up to 0.25% of the principal amount of the Bonds. If all the Bonds are not sold at the initial offering price, the underwriters may change the offering price and the other selling terms.

The Bonds are a new issue of securities with no established trading market. LG&E has been advised by the underwriters that the underwriters intend to make a market in the Bonds as permitted by applicable laws and regulations. The underwriters are not obligated, however, to do so and any such market making may be discontinued at any time without notice at the sole discretion of the underwriters. Accordingly, no assurance can be given as to the liquidity of, or trading markets for, the Bonds.

In connection with the offering, the underwriters may purchase and sell Bonds in the open market. These transactions may include short sales, stabilizing transactions and purchases to cover positions created by short sales. Short sales involve the sale by the underwriters of a greater number of Bonds than they are required to purchase in the offering. Stabilizing transactions consist of certain bids or purchases made for the purpose of preventing or retarding a decline in the market price of the Bonds while the offering is in progress.

The underwriters also may impose a penalty bid. This occurs when a particular underwriter repays to the underwriters a portion of the underwriting discount received by it because the representatives have repurchased Bonds sold by or for the account of such underwriter in stabilizing or short covering transactions.

These activities by the underwriters, as well as other purchases by the underwriters for their own accounts, may stabilize, maintain or otherwise affect the market price of the Bonds. As a result, the price of the Bonds may be higher than the price that otherwise might exist in the open market. If these activities are commenced, they may be discontinued by the underwriters at any time. These transactions may be effected in the over-the-counter market or otherwise.

It is expected that delivery of the Bonds will be made on or about the day specified on the cover page of this prospectus supplement, which will be the fifth business day (T+5) following the date of this prospectus supplement. Under Rule 15c6-1 under the Exchange Act, trades in the secondary market generally are required to settle within three business days (T+3), unless the parties to any such trade expressly agree otherwise. Accordingly, the purchasers who wish to trade the Bonds on the date of this prospectus supplement or the next succeeding business day will be required to specify an alternative settlement cycle at the time of any such trade to prevent a failed settlement. Purchasers of the Bonds who wish to trade the Bonds on the date of this prospectus supplement or the next succeeding business day should consult their own advisors.

LG&E estimates that its share of the total expenses of the offering, excluding the underwriting discount, will be approximately $500,000.

LG&E has agreed to indemnify the several underwriters against certain liabilities, including liabilities under the Securities Act of 1933, as amended.

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include sales and trading, commercial and investment banking, advisory, investment management, investment research, principal investment, hedging, market making, brokerage and other financial and non-financial activities and services. Certain of the underwriters and their respective affiliates have provided, and may in the future provide, a variety of these services to LG&E and to persons and entities with relationships with LG&E, for which they received or will receive customary fees and expenses. In particular, certain of the underwriters or their affiliates are agents or lenders under the credit or other borrowing facilities of LG&E and its affiliates.

In the ordinary course of their various business activities, the underwriters and their respective affiliates, officers, directors and employees may purchase, sell or hold a broad array of investments and actively trade securities, derivatives, loans, commodities, currencies, credit default swaps and other financial instruments for their own account and for the accounts of their customers, and such investment and trading activities may involve or relate to assets, securities and/or instruments of LG&E (directly, as collateral securing other obligations or otherwise) and/or persons and entities with relationships with LG&E. The underwriters and their respective affiliates may also communicate independent investment recommendations, market color or trading ideas and/or publish or express independent research views in respect of such assets, securities or instruments and may at any time hold, or recommend to clients that they should acquire, long and/or short positions in such assets, securities and instruments.

The offering of the Bonds by the underwriters is subject to receipt and acceptance and subject to the underwriters' right to reject any order in whole or in part.

VALIDITY OF THE BONDS

Pillsbury Winthrop Shaw Pittman LLP, New York, New York, and Dorothy E. O'Brien, Esq., Deputy General Counsel, Legal and Environmental Affairs of LG&E will pass upon the validity of the Bonds for LG&E. Davis Polk & Wardwell LLP, New York, New York, will pass upon the validity of the Bonds for the underwriters. However, all matters pertaining to the organization of LG&E and LG&E's title to its property and the liens of the Mortgage upon LG&E's properties will be passed upon only by Ms. O'Brien and Frost & Brown Todd LLC, Louisville, Kentucky. As to matters involving the law of the Commonwealth of Kentucky, Pillsbury Winthrop Shaw Pittman LLP and Davis Polk & Wardwell LLP will rely on the opinion of Ms. O'Brien, Frost & Brown Todd LLC and Stoll Keenon Ogden PLLC, Louisville, Kentucky.

PROSPECTUS

PPL Corporation
PPL Capital Funding, Inc.
PPL Energy Supply, LLC
PPL Electric Utilities Corporation
Two North Ninth Street
Allentown, Pennsylvania 18101-1179
(610) 774-5151

LG&E and KU Energy LLC
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-2000

Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507
(502) 627-2000

PPL Corporation

Common Stock, Preferred Stock,
Stock Purchase Contracts, Stock Purchase Units and Depositary Shares

PPL Capital Funding, Inc.

Debt Securities and Subordinated Debt Securities
Guaranteed by PPL Corporation as described in a supplement to this prospectus

PPL Energy Supply, LLC

Debt Securities, Subordinated Debt Securities and Preferred Securities

PPL Electric Utilities Corporation

Preferred Stock, Preference Stock, Depositary Shares and Debt Securities

LG&E and KU Energy LLC

Debt Securities

Louisville Gas and Electric Company

Debt Securities

Kentucky Utilities Company

Debt Securities

We will provide the specific terms of these securities in supplements to this prospectus. You should read this prospectus and the supplements carefully before you invest.

We may offer the securities directly or through underwriters or agents. The applicable prospectus supplement will describe the terms of any particular plan of distribution.

Investing in the securities involves certain risks. See "Risk Factors" on page 4.

PPL Corporation's common stock is listed on the New York Stock Exchange and trades under the symbol "PPL."

These securities have not been approved or disapproved by the Securities and Exchange Commission or any state securities commission, nor has the Securities and Exchange Commission or any state securities commission determined that this prospectus is accurate or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus is March 28, 2012.

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ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement that PPL Corporation, PPL Capital Funding, Inc. ("PPL Capital Funding"), PPL Energy Supply, LLC ("PPL Energy Supply"), PPL Electric Utilities Corporation ("PPL Electric"), LG&E and KU Energy LLC ("LKE"), Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") have each filed with the Securities and Exchange Commission, or SEC, using the "shelf" registration process. Under this shelf process, we may, from time to time, sell combinations of the securities described in this prospectus in one or more offerings. Each time we sell securities, we will provide a prospectus supplement that will contain a description of the securities we will offer and specific information about the terms of that offering. The prospectus supplement may also add, update or change information contained in this prospectus. You should read both this prospectus and any prospectus supplement together with additional information described under "Where You Can Find More Information."

We may use this prospectus to offer from time to time:

- shares of PPL Corporation Common Stock, par value $.01 per share ("PPL Common Stock");
- shares of PPL Corporation Preferred Stock, par value $.01 per share ("PPL Preferred Stock");
- contracts or other rights to purchase shares of PPL Common Stock or PPL Preferred Stock ("PPL Stock Purchase Contracts");
- stock purchase units, each representing (1) a PPL Stock Purchase Contract and (2) debt securities or preferred trust securities of third parties (such as debt securities or subordinated debt securities of PPL Capital Funding, preferred trust securities of a subsidiary trust or United States Treasury securities) that are pledged to secure the stock purchase unit holders' obligations to purchase PPL Common Stock or PPL Preferred Stock under the PPL Stock Purchase Contracts ("PPL Stock Purchase Units");
- PPL Corporation's Depositary Shares, issued under a deposit agreement and representing a fractional interest in PPL Preferred Stock;
- PPL Capital Funding's unsecured and unsubordinated debt securities ("PPL Capital Funding Debt Securities");
- PPL Capital Funding's unsecured and subordinated debt securities ("PPL Capital Funding Subordinated Debt Securities");
- PPL Energy Supply's unsecured and unsubordinated debt securities;
- PPL Energy Supply's unsecured and subordinated debt securities;
- PPL Energy Supply's preferred limited liability company membership interests;
- PPL Electric's Series Preferred Stock ("PPL Electric Preferred Stock");
- PPL Electric's Preference Stock ("PPL Electric Preference Stock");
- PPL Electric's Depositary Shares, issued under a deposit agreement and representing a fractional interest in PPL Electric Preferred Stock or PPL Electric Preference Stock;
- PPL Electric's First Mortgage Bonds issued under PPL Electric's 2001 indenture, as amended and supplemented ("PPL Electric First Mortgage Bonds"), which will be secured by the lien of the 2001 indenture on PPL Electric's electric distribution and certain transmission properties (subject to certain exceptions to be described in a prospectus supplement);
- LKE's unsecured and unsubordinated debt securities;
- LG&E's First Mortgage Bonds issued under LG&E's 2010 indenture, as amended and supplemented ("LG&E First Mortgage Bonds"), which will be secured by the lien of the 2010 indenture on LG&E's

Kentucky electric generation, transmission and distribution properties and natural gas distribution properties (subject to certain exceptions to be described in a prospectus supplement); and

- KU's First Mortgage Bonds issued under KU's 2010 indenture, as amended and supplemented ("KU First Mortgage Bonds"), which will be secured by the lien of the 2010 indenture on KU's Kentucky electric generation, transmission and distribution properties (subject to certain exceptions to be described in a prospectus supplement).

We sometimes refer to the securities listed above collectively as the "Securities."

PPL Corporation will fully and unconditionally guarantee the payment of principal, premium and interest on the PPL Capital Funding Debt Securities and PPL Capital Funding Subordinated Debt Securities as will be described in supplements to this prospectus. We sometimes refer to PPL Corporation's guarantees of PPL Capital Funding Debt Securities as "PPL Guarantees" and PPL Corporation's guarantees of PPL Capital Funding Subordinated Debt Securities as the "PPL Subordinated Guarantees."

Information contained herein relating to each registrant is filed separately by such registrant on its own behalf. No registrant makes any representation as to information relating to any other registrant or Securities or guarantees issued by any other registrant, except that information relating to PPL Capital Funding's Securities is also attributed to PPL Corporation.

As used in this prospectus, the terms "we," "our" and "us" generally refer to:

- PPL Corporation with respect to Securities, PPL Guarantees or PPL Subordinated Guarantees issued by PPL Corporation or PPL Capital Funding;
- PPL Energy Supply with respect to Securities issued by PPL Energy Supply;
- PPL Electric, with respect to Securities issued by PPL Electric;
- LKE, with respect to Securities issued by LKE;
- LG&E, with respect to Securities issued by LG&E; and
- KU, with respect to Securities issued by KU.

For more detailed information about the Securities, the PPL Guarantees and the PPL Subordinated Guarantees, you can read the exhibits to the registration statement. Those exhibits have been either filed with the registration statement or incorporated by reference to earlier SEC filings listed in the registration statement.

RISK FACTORS

Investing in the Securities involves certain risks. You are urged to read and consider the risk factors relating to an investment in the Securities described in the Annual Reports on Form 10-K of PPL Corporation, PPL Energy Supply, PPL Electric, LKE, LG&E and KU, as applicable, for the year ended December 31, 2011, and incorporated by reference in this prospectus. Before making an investment decision, you should carefully consider these risks as well as other information we include or incorporate by reference in this prospectus. The risks and uncertainties we have described are not the only ones affecting PPL Corporation, PPL Energy Supply, PPL Electric, LKE, LG&E and KU. The prospectus supplement applicable to each type or series of Securities we offer may contain a discussion of additional risks applicable to an investment in us and the particular type of Securities we are offering under that prospectus supplement.

FORWARD-LOOKING INFORMATION

Certain statements included or incorporated by reference in this prospectus, including statements concerning expectations, beliefs, plans, objectives, goals, strategies, future events or performance and underlying assumptions and other statements which are other than statements of historical fact are "forward-looking statements" within the meaning of the federal securities laws. Although we believe that the expectations and assumptions reflected in these statements are reasonable, there can be no assurance that these expectations will prove to be correct. Forward-looking statements are subject to many risks and uncertainties, and actual results may differ materially from the results discussed in forward-looking statements. In addition to the specific factors discussed in the "Risk Factors" section in this prospectus and our reports that are incorporated by reference, the following are among the important factors that could cause actual results to differ materially from the forward- looking statements:

- fuel supply cost and availability;
- continuing ability to recover fuel costs and environmental expenditures in a timely manner at LG&E and KU, and natural gas supply costs at LG&E;
- weather conditions affecting generation, customer energy use and operating costs;
- operation, availability and operating costs of existing generation facilities;
- the length of scheduled and unscheduled outages at our generating facilities;
- transmission and distribution system conditions and operating costs;
- potential expansion of alternative sources of electricity generation;
- potential laws or regulations to reduce emissions of "greenhouse" gases or the physical effects of climate change;
- collective labor bargaining negotiations;
- the outcome of litigation against us;
- potential effects of threatened or actual terrorism, war or other hostilities, or natural disasters;
- our commitments and liabilities;
- market demand and prices for energy, capacity, transmission services, emission allowances, renewable energy credits and delivered fuel;
- competition in retail and wholesale power and natural gas markets;
- liquidity of wholesale power markets;
- defaults by counterparties under energy, fuel or other power product contracts;
- market prices of commodity inputs for ongoing capital expenditures;
- capital market conditions, including the availability of capital or credit, changes in interest rates and certain economic indices, and decisions regarding capital structure;
- stock price performance of PPL Corporation;
- volatility in the fair value of debt and equity securities and its impact on the value of assets in PPL Susquehanna's nuclear plant decommissioning trust funds and in defined benefit plans, and the potential cash funding requirements if fair value declines;
- interest rates and their effect on pension, retiree medical, and nuclear decommissioning liabilities, and interest payable on certain debt securities;
- volatility in or the impact of other changes in financial or commodity markets and economic conditions;
- profitability and liquidity, including access to capital markets and credit facilities;
- new accounting requirements or new interpretations or applications of existing requirements;

- changes in securities and credit ratings;
- foreign currency exchange rates;
- current and future environmental conditions, regulations and other requirements and the related costs of compliance, including environmental capital expenditures, emission allowance costs and other expenses;
- legal, regulatory, political, market or other reactions to the 2011 incident at the nuclear generating facility at Fukushima, Japan, including additional Nuclear Regulatory Commission requirements;
- political, regulatory or economic conditions in states, regions or countries where we conduct business;
- receipt of necessary governmental permits, approvals and rate relief;
- new state, federal or foreign legislation, including new tax, environmental, healthcare or pension-related legislation;
- state, federal and foreign regulatory developments;
- the outcome of any rate cases by our regulated utilities;
- the impact of any state, federal or foreign investigations applicable to us and the energy industry;
- the effect of any business or industry restructuring;
- development of new projects, markets and technologies;
- performance of new ventures; and
- business dispositions or acquisitions and our ability to successfully operate such acquired businesses and realize expected benefits from business acquisitions.

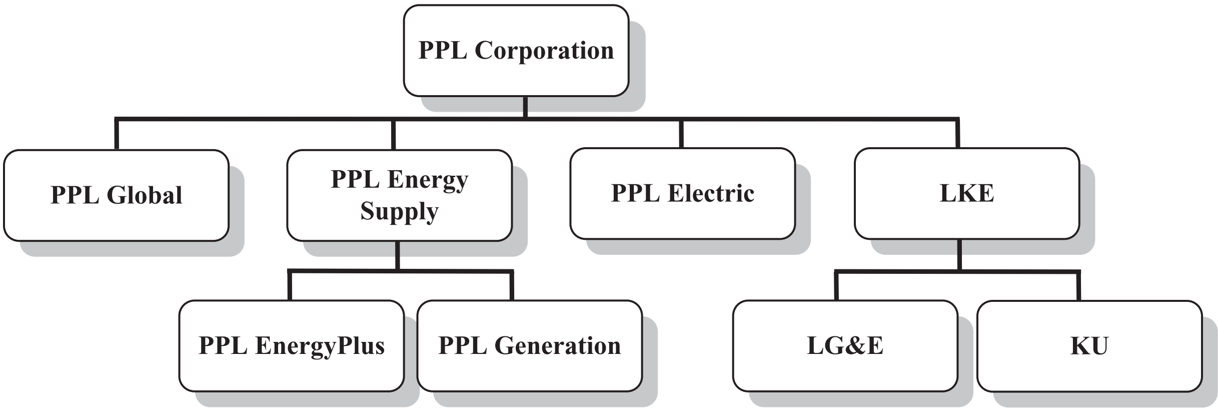
Any such forward-looking statements should be considered in light of such important factors and in conjunction with other documents we file with the SEC.

New factors that could cause actual results to differ materially from those described in forward-looking statements emerge from time to time, and it is not possible for us to predict all such factors, or the extent to which any such factor or combination of factors may cause actual results to differ from those contained in any forward-looking statement. Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable law, we undertake no obligation to update the information contained in such statement to reflect subsequent developments or information.

PPL CORPORATION

PPL Corporation, incorporated in 1994 and headquartered in Allentown, Pennsylvania, is an energy and utility holding company. Through its subsidiaries, PPL Corporation generates electricity from power plants in the northeastern, northwestern and southeastern United States; markets wholesale or retail energy primarily in the northeastern and northwestern portions of the United States; and delivers electricity to customers in Pennsylvania, Kentucky, Virginia, Tennessee and the United Kingdom, and natural gas to customers in Kentucky.

PPL Corporation's principal subsidiaries are shown below:



PPL Corporation conducts its operations through the following segments:

Supply

PPL Corporation, through its indirect, wholly owned subsidiaries, PPL Generation, LLC ("PPL Generation") and PPL EnergyPlus, LLC ("PPL EnergyPlus") owns and operates electricity generating power plants, markets and trades this electricity and other purchased power to competitive wholesale and retail markets and acquires and develops competitive domestic generation projects. Both of these subsidiaries are direct, wholly owned subsidiaries of PPL Energy Supply. See "PPL Energy Supply, LLC" below for more information.

Pennsylvania Regulated

PPL Corporation's Pennsylvania Regulated segment includes the regulated electric delivery operations of PPL Electric. As of December 31, 2011, PPL Electric delivered electricity to approximately 1.4 million customers in eastern and central Pennsylvania. See "PPL Electric Utilities Corporation" below for more information.

Kentucky Regulated

The Kentucky Regulated segment consists of the operations of LKE, which owns and operates regulated public utilities engaged in the generation, transmission, distribution and sale of electricity and the distribution and sale of natural gas, representing primarily the activities of LG&E and KU. As of December 31, 2011, LG&E provided electric service to approximately 394,000 customers and provided natural gas service to approximately 319,000 customers in Kentucky, and KU delivered electricity to approximately 541,000 customers in Kentucky and Virginia. See "Louisville Gas and Electric Company" and "Kentucky Utilities Company," respectively, for more information.

International Regulated

The International Regulated segment consists primarily of electric distribution operations in the United Kingdom. Through its subsidiaries, as of December 31, 2011, PPL Global delivered electricity to approximately 7.8 million end-users in the United Kingdom. PPL Global is a wholly owned, indirect subsidiary of PPL Corporation.

PPL Corporation's subsidiaries, including PPL Energy Supply, PPL Electric, LKE, LG&E and KU, are separate legal entities and are not liable for the debts of PPL Corporation, and PPL Corporation is not liable for the debts of its subsidiaries (other than under the PPL Guarantees of PPL Capital Funding Debt Securities and PPL Subordinated Guarantees of PPL Capital Funding Subordinated Debt Securities). None of PPL Energy Supply, PPL Electric, LKE, LG&E or KU will guarantee or provide other credit or funding support for the Securities to be offered by PPL Corporation pursuant to this prospectus.

PPL CAPITAL FUNDING, INC.

PPL Capital Funding is a Delaware corporation and a wholly owned subsidiary of PPL Corporation. PPL Capital Funding's primary business is to provide PPL Corporation with financing for its operations. PPL Corporation will fully and unconditionally guarantee the payment of principal, premium and interest on the PPL Capital Funding Debt Securities pursuant to the PPL Guarantees and the PPL Capital Funding Subordinated Debt Securities pursuant to the PPL Subordinated Guarantees, as will be described in supplements to this prospectus.

PPL ENERGY SUPPLY, LLC

PPL Energy Supply, formed in 2000 and headquartered in Allentown, Pennsylvania, is an energy company engaged through its subsidiaries in the generation and marketing of electricity, primarily in the northeastern and northwestern power markets of the United States. PPL Energy Supply's major operating subsidiaries are PPL Generation and PPL Energy Plus. PPL Energy Supply is an indirect wholly owned subsidiary of PPL Corporation. See "PPL Corporation" above for more information.

PPL Generation and PPL EnergyPlus

At December 31, 2011, PPL Energy Supply owned or controlled, through its subsidiaries, 10,508 MW of electric power generation capacity and was implementing capital projects at certain of its existing generation facilities in Pennsylvania and Montana to provide 191 MW of additional generating capacity by the end of 2013. Generating capacity controlled by PPL Generation and other PPL Energy Supply subsidiaries includes power obtained through PPL EnergyPlus' tolling or power purchase agreements.

PPL Generation owns and operates a portfolio of competitive domestic power generating assets. Its power plants are located in Pennsylvania and Montana and are fueled by coal, uranium, natural gas, oil and water. The electricity from these plants is sold to PPL Energy Plus under FERC-jurisdictional power purchase agreements.

PPL Energy Plus sells electricity produced by PPL Generation subsidiaries, participates in wholesale market load-following auctions, and markets various energy products and commodities such as: capacity, transmission, financial transmission rights, coal, natural gas, oil, uranium, emission allowances, renewable energy credits and other commodities in competitive wholesale and competitive retail markets, primarily in the northeastern and northwestern United States.

PPL Energy Plus also provides energy-related products and services, such as engineering and mechanical contracting, construction and maintenance services, to commercial and industrial customers.

Neither PPL Corporation nor any of its subsidiaries or affiliates will guarantee or provide other credit or funding support for the Securities to be offered by PPL Energy Supply pursuant to this prospectus.

PPL ELECTRIC UTILITIES CORPORATION

PPL Electric, incorporated in 1920 and headquartered in Allentown, Pennsylvania, is a direct subsidiary of PPL Corporation and a regulated public utility. As of December 31, 2011, PPL Electric delivered electricity to approximately 1.4 million customers in eastern and central Pennsylvania. PPL Electric also provides electricity supply as a "provider of last resort," or "PLR," to retail customers in that territory that do not choose an alternative electricity provider.

Neither PPL Corporation nor any of its subsidiaries or affiliates will guarantee or provide other credit or funding support for the Securities to be offered by PPL Electric pursuant to this prospectus.

LG&E AND KU ENERGY LLC

LKE, a holding company formed in 2003, is a wholly owned subsidiary of PPL Corporation. LKE's regulated utility operations are conducted through its subsidiaries, LG&E and KU, which constitute substantially all of LKE's assets. LG&E and KU are regulated public utilities engaged in the generation, transmission, distribution and sale of electric energy. LG&E also engages in the distribution and sale of natural gas. LG&E and KU maintain their separate identities and serve customers in Kentucky under their respective names. KU also serves customers in Virginia under the Old Dominion Power name and customers in Tennessee under the KU name.

See "Louisville Gas and Electric Company" and "Kentucky Utilities Company" below for additional information about LG&E and KU.

Neither PPL Corporation nor any of its subsidiaries or affiliates will guarantee or provide other credit or funding support for the Securities to be offered by LKE pursuant to this prospectus.

LOUISVILLE GAS AND ELECTRIC COMPANY

LG&E, headquartered in Louisville, Kentucky and incorporated in Kentucky in 1913, is a regulated utility engaged in the generation, transmission, distribution and sale of electricity and the distribution and sale of natural gas in Kentucky. At December 31, 2011, LG&E owned or controlled 3,352 MW of electric power generation capacity. Subject to certain regulatory approvals, LG&E is planning capital projects at certain of its existing generation facilities to provide 483 MW of additional generating capacity by 2016. LG&E also anticipates retiring 563 MW of generating capacity by the end of 2015 to meet certain environmental regulations. As of December 31, 2011, LG&E provided electric service to approximately 394,000 customers in Louisville and adjacent areas in Kentucky, covering approximately 700 square miles in nine counties. As of December 31, 2011, LG&E provided natural gas service to approximately 319,000 customers in its electric service area and seven additional counties in Kentucky.

Neither PPL Corporation nor any of its subsidiaries or affiliates will guarantee or provide other credit or funding support for the Securities to be offered by LG&E pursuant to this prospectus.

KENTUCKY UTILITIES COMPANY

KU, headquartered in Lexington, Kentucky and incorporated in Kentucky in 1912 and Virginia in 1991, is a regulated utility engaged in the generation, transmission, distribution and sale of electricity in Kentucky, Virginia and Tennessee. At December 31, 2011, KU owned or controlled 4,833 MW of electric power generation capacity. Subject to certain regulatory approvals, KU is planning capital projects at certain of its existing generation facilities to provide 652 MW of additional generating capacity by 2016. KU also anticipates retiring 234 MW of generating capacity by the end of 2015 to meet certain environmental regulations. As of December 31, 2011, KU provided electric service to approximately 512,000 customers in 77 counties in central, southeastern and western Kentucky and approximately 29,000 customers in five counties in southwestern Virginia. As of December 31, 2011, KU's service area covered approximately 4,800 non-contiguous square miles. KU also sells wholesale electric energy to 12 municipalities in Kentucky. In Virginia, KU operates under the name Old Dominion Power Company.

Neither PPL Corporation nor any of its subsidiaries or affiliates will guarantee or provide other credit or funding support for the Securities to be offered by KU pursuant to this prospectus.

The offices of PPL Corporation, PPL Capital Funding, PPL Energy Supply and PPL Electric are located at Two North Ninth Street, Allentown, Pennsylvania 18101-1179 (Telephone number (610) 774-5151).

The offices of LKE and LG&E are located at 220 West Main Street, Louisville, Kentucky 40202 (Telephone number (502) 627-2000).

The offices of Kentucky Utilities Company are located at One Quality Street, Lexington, Kentucky 40507 (Telephone number (502) 627-2000).

The information above concerning PPL Corporation, PPL Capital Funding, PPL Energy Supply, PPL Electric, LKE, LG&E and KU and, if applicable, their respective subsidiaries is only a summary and does not purport to be comprehensive. For additional information about these companies, including certain assumptions, risks and uncertainties involved in the forward-looking statements contained or incorporated by reference in this prospectus, you should refer to the information described in "Where You Can Find More Information."

USE OF PROCEEDS

Except as otherwise described in a prospectus supplement, the net proceeds from the sale of the PPL Capital Funding Debt Securities and the PPL Capital Funding Subordinated Debt Securities will be loaned to PPL Corporation and/or its subsidiaries, and PPL Corporation and/or its subsidiaries are expected to use the proceeds of such loans, and the proceeds of the other Securities issued by PPL Corporation, for general corporate purposes, including repayment of debt. Except as otherwise described in a prospectus supplement, each of PPL Energy Supply, PPL Electric, LKE, LG&E and KU is expected to use the proceeds of the Securities it issues for general corporate purposes, including repayment of debt, and for capital expenditures related to construction costs.

RATIOS OF EARNINGS TO FIXED CHARGES AND EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

PPL Corporation

The following table sets forth PPL Corporation's ratio of earnings to fixed charges and ratio of earnings to combined fixed charges and preferred stock dividends for the periods indicated:

	Twelve Months Ended December 31,				
	2011	2010	2009	2008	2007
Ratio of earnings to fixed charges and ratio of earnings to combined fixed charges and preferred stock dividends (a)	3.1	2.7	1.9	3.1	2.8

(a) See PPL Corporation's reports on file with the SEC pursuant to the Securities Exchange Act of 1934, as amended (the "Exchange Act"), as described under "Where You Can Find More Information" for more information. PPL Corporation had no preferred securities outstanding during the periods indicated; therefore, the ratio of earnings to combined fixed charges and preferred stock dividends is the same as the ratio of earnings to fixed charges.

PPL Energy Supply

The following table sets forth PPL Energy Supply's ratio of earnings to fixed charges and ratio of earnings to combined fixed charges and preferred securities dividends for the periods indicated:

	Twelve Months Ended December 31,				
	2011	2010	2009	2008	2007
Ratio of earnings to fixed charges and ratio of earnings to combined fixed charges and preferred securities dividends (a)	5.5	2.7	0.6(b)	2.2	2.3

(a) See PPL Energy Supply's reports on file with the SEC pursuant to the Exchange Act as described under "Where You Can Find More Information" for more information. PPL Energy Supply had no preferred securities outstanding during the periods indicated; therefore, the ratio of earnings to combined fixed charges and preferred securities dividends is the same as the ratio of earnings to fixed charges.

(b) Upon reflecting the reclassification of PPL Global's operating results as Discontinued Operations, earnings were less than fixed charges for this period. See PPL Energy Supply's reports on file with the SEC pursuant to the Exchange Act for additional information. The total amount of fixed charges for this period was approximately $364 million and the total amount of earnings was approximately $206 million. The amount of the deficiency, or the amount of fixed charges in excess of earnings, was approximately $158 million.

PPL Electric

The following table sets forth PPL Electric's ratio of earnings to fixed charges and ratio of earnings to combined fixed charges and preferred stock dividends for the periods indicated:

	Twelve Months Ended December 31,				
	2011	2010	2009	2008	2007
Ratio of earnings to fixed charges (a)	3.4	2.9	2.8	3.4	2.7
Ratio of earnings to combined fixed charges and preferred stock dividends (a)	2.9	2.4	2.3	2.8	2.3

(a) See PPL Electric's reports on file with the SEC pursuant to the Exchange Act as described under "Where You Can Find More Information" for more information.

LKE

The following table sets forth LKE's ratio of earnings to fixed charges and ratio of earnings to combined fixed charges for the periods indicated. The following table includes the periods before and after PPL Corporation's acquisition of LKE on November 1, 2010, and is labeled as Predecessor or Successor.

	Successor		Predecessor			
	12 Months Ended Dec. 31, 2011	2 Months Ended Dec. 31, 2010	10 Months Ended Oct. 31, 2010	Twelve Months Ended Dec. 31		
				2009	2008	2007
Ratio of earnings to fixed charges (a)	3.7	3.9	2.7	2.3	2.5	2.9

(a) See LKE's reports on file with the SEC pursuant to the Exchange Act as described under "Where You Can Find More Information" for more information.

LG&E

The following table sets forth LG&E's ratio of earnings to fixed charges and ratio of earnings to combined fixed charges for the periods indicated. The following table includes the periods before and after PPL Corporation's acquisition of LKE, LG&E's parent, on November 1, 2010, and is labeled as Predecessor or Successor.

	Successor		Predecessor			
	12 Months Ended Dec. 31, 2011	2 Months Ended Dec. 31, 2010	10 Months Ended Oct. 31, 2010	Twelve Months Ended Dec. 31		
				2009	2008	2007
Ratio of earnings to fixed charges (a)	5.2	4.8	4.7	3.7	3.8	4.4

(a) See LG&E's reports on file with the SEC pursuant to the Exchange Act as described under "Where You Can Find More Information" for more information.

KU

The following table sets forth KU's ratio of earnings to fixed charges and ratio of earnings to combined fixed charges for the periods indicated. The following table includes the periods before and after PPL Corporation's acquisition of LKE, KU's parent, on November 1, 2010, and is labeled as Predecessor or Successor.

	Successor		Predecessor			
	12 Months Ended Dec. 31, 2011	2 Months Ended Dec. 31, 2010	10 Months Ended Oct. 31, 2010	Twelve Months Ended Dec. 31		
				2009	2008	2007
Ratio of earnings to fixed charges (a)	4.8	6.0	4.0	3.7	3.9	5.1

(a) See KU's reports on file with the SEC pursuant to the Exchange Act as described under "Where You Can Find More Information" for more information.

WHERE YOU CAN FIND MORE INFORMATION

Available Information

PPL Corporation, PPL Energy Supply, PPL Electric, LKE, LG&E and KU each file reports and other information with the SEC. You may obtain copies of this information by mail from the Public Reference Room of the SEC, 100 F Street, N.E., Room 1580, Washington, D.C. 20549, at prescribed rates. Further information on the operation of the SEC's Public Reference Room in Washington, D.C. can be obtained by calling the SEC at 1-800-SEC-0330.

PPL Corporation's Internet Web site is www.pplweb.com. On the Investor Center page of that Web site PPL Corporation provides access to all SEC filings of PPL Corporation, PPL Energy Supply, PPL Electric, LKE, LG&E and KU free of charge, as soon as reasonably practicable after filing with the SEC. The information at PPL Corporation's Internet Web site is not incorporated in this prospectus by reference, and you should not consider it a part of this prospectus. Additionally, PPL Corporation's, PPL Energy Supply's, PPL Electric's, LKE's, LG&E's and KU's filings are available at the SEC's Internet Web site (www.sec.gov).

In addition, reports, proxy statements and other information concerning PPL Corporation, PPL Energy Supply and PPL Electric can be inspected at their offices at Two North Ninth Street, Allentown, Pennsylvania 18101-1179; reports and other information concerning LKE and LG&E can be inspected at their offices at 220 West Main Street, Louisville, Kentucky 40202, and reports and other information concerning KU can be inspected at its office at One Quality Street, Lexington, Kentucky 40507.

Incorporation by Reference

Each of PPL Corporation, PPL Energy Supply, PPL Electric, LKE, LG&E and KU will "incorporate by reference" information into this prospectus by disclosing important information to you by referring you to another document that it files separately with the SEC. The information incorporated by reference is deemed to be part of this prospectus, and later information that we file with the SEC will automatically update and supersede that information. This prospectus incorporates by reference the documents set forth below that have been previously filed with the SEC. These documents contain important information about the registrants.

PPL Corporation

SEC Filings (File No. 1-11459)	Period/Date
Annual Report on Form 10-K	Year ended December 31, 2011
PPL Corporation's 2011 Notice of Annual Meeting and Proxy Statement	Filed on April 6, 2011
Current Reports on Form 8-K	Filed on January 18, 2012, January 31, 2012, February 1, 2012, February 27, 2012, February 29, 2012, March 27, 2012 and March 28, 2012
PPL Corporation's Registration Statement on Form 8-B	Filed on April 27, 1995

PPL Energy Supply

SEC Filings (File No. 1-32944)	Period/Date
Annual Report on Form 10-K	Year ended December 31, 2011
Current Reports on Form 8-K	Filed on February 27, 2012 and February 29, 2012

PPL Electric

SEC Filings (File No. 1-905)	Period/Date
Annual Report on Form 10-K	Year ended December 31, 2011
Current Reports on Form 8-K	Filed on February 29, 2012

LKE

SEC Filings (File No. 333-173665)	Period/Date
Annual Report on Form 10-K	Year ended December 31, 2011

LG&E

SEC Filings (File No. 1-2893)	Period/Date
Annual Report on Form 10-K	Year ended December 31, 2011

KU

SEC Filings (File No. 1-3464)	Period/Date
Annual Report on Form 10-K	Year ended December 31, 2011

Additional documents that PPL Corporation, PPL Energy Supply, PPL Electric, LKE, LG&E and KU file with the SEC pursuant to Sections 13(a), 13(c), 14 or 15(d) of the Exchange Act, between the date of this prospectus and the termination of the offering of the Securities are also incorporated herein by reference. In addition, any additional documents that PPL Corporation, PPL Energy Supply, PPL Electric, LKE, LG&E or KU file with the SEC pursuant to these sections of the Exchange Act after the date of the filing of the registration statement containing this prospectus, and prior to the effectiveness of the registration statement are also incorporated herein by reference. Unless specifically stated to the contrary, none of the information that PPL Corporation, PPL Energy Supply, PPL Electric, LKE, LG&E or KU files or discloses under Items 2.02 or 7.01 of any Current Report on Form 8-K that have been furnished or may from time to time be furnished with the SEC is or will be incorporated by reference into, or otherwise included in, this prospectus.

Each of PPL Corporation, PPL Energy Supply, PPL Electric, LKE, LG&E and KU will provide without charge to each person, including any beneficial owner, to whom a copy of this prospectus has been delivered, a copy of any and all of its filings with the SEC. You may request a copy of these filings by writing or telephoning the appropriate registrant at:

For PPL Corporation, PPL Energy Supply and PPL Electric:
Two North Ninth Street
Allentown, Pennsylvania 18101-1179
Attention: Treasurer
Telephone: 1-800-345-3085

For LKE and LG&E:
220 West Main Street
Louisville, Kentucky 40202
Attention: Treasurer
Telephone: 1-800-345-3085

For KU:
One Quality Street
Lexington, Kentucky 40507
Attention: Treasurer
Telephone: 1-800-345-3085

No separate financial statements of PPL Capital Funding are included herein or incorporated herein by reference. PPL Corporation and PPL Capital Funding do not consider those financial statements to be material to holders of the PPL Capital Funding Debt Securities or PPL Capital Funding Subordinated Debt Securities because (1) PPL Capital Funding is a wholly owned subsidiary that was formed for the primary purpose of providing financing for PPL Corporation and its subsidiaries, (2) PPL Capital Funding does not currently engage in any independent operations and (3) PPL Capital Funding does not currently plan to engage, in the future, in more than minimal independent operations. See "PPL Capital Funding." PPL Capital Funding has received a "no action" letter from the Staff of the SEC stating that the Staff would not raise any objection if PPL Capital Funding does not file periodic reports under Sections 13 and 15(d) of the Exchange Act. Accordingly, PPL Corporation and PPL Capital Funding do not expect PPL Capital Funding to file those reports.

EXPERTS

The consolidated financial statements of PPL Corporation, PPL Energy Supply, LLC and PPL Electric Utilities Corporation appearing in such companies' Annual Reports (Form 10-K) for the year ended December 31, 2011 including schedules appearing therein, and the effectiveness of PPL Corporation's internal control over financial reporting as of December 31, 2011, have been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in its reports thereon included therein, and incorporated herein by reference which, as to the year 2010, are based in part on the report of PricewaterhouseCoopers LLP, independent registered public accounting firm. Such consolidated financial statements are incorporated herein by reference in reliance upon such reports given on the authority of such firm as experts in accounting and auditing.

The audited historical financial statements of Central Networks (collectively Central Networks East plc, Central Networks Limited and certain other related assets and liabilities) included in PPL Corporation's Current Report on Form 8-K dated March 27, 2012 have been incorporated herein by reference in reliance on the report of PricewaterhouseCoopers LLP, independent accountants, given on the authority of said firm as experts in auditing and accounting.

The consolidated financial statements of LG&E and KU Energy LLC and the financial statements of Louisville Gas and Electric Company and Kentucky Utilities Company appearing in such companies' Annual Reports (Form 10-K) for the year ended December 31, 2011 including schedules appearing therein have been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in its reports included therein, and incorporated herein by reference. Such financial statements are incorporated herein by reference in reliance upon such reports given on the authority of such firm as experts in accounting and auditing. The consolidated financial statements of LG&E and KU Energy LLC and the financial statements of Louisville Gas and Electric Company and Kentucky Utilities Company as of December 31, 2010 and for the periods from January 1, 2010 to October 31, 2010, and November 1, 2010 to December 1, 2010, and for the year ended December 31, 2009 incorporated herein by reference have been so incorporated in reliance on the reports of PricewaterhouseCoopers LLP, independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

VALIDITY OF THE SECURITIES AND THE PPL GUARANTEES

Dewey & LeBoeuf LLP, New York, New York or Simpson Thacher & Bartlett LLP, New York, New York and Frederick C. Paine, Esq., Senior Counsel of PPL Services Corporation will pass upon the validity of the Securities, the PPL Guarantees and the PPL Subordinated Guarantees for PPL Corporation, PPL Capital Funding, PPL Energy Supply and PPL Electric. Dewey & LeBoeuf LLP and John P. Fendig, Esq. of LG&E and KU Energy LLC will pass upon the validity of any LKE, LG&E and KU Securities for those issuers. Sullivan & Cromwell LLP, New York, New York or Davis Polk & Wardwell LLP, New York, New York will pass upon the validity of the Securities, the PPL Guarantees and the PPL Subordinated Guarantees for any underwriters or agents. Dewey & LeBoeuf LLP, Simpson Thacher & Bartlett LLP, Sullivan & Cromwell LLP and Davis Polk & Wardwell LLP will rely on the opinion of Mr. Paine as to matters involving the law of the Commonwealth of Pennsylvania and on the opinion of Mr. Fendig as to matters involving the laws of the Commonwealths of Kentucky and Virginia and the State of Tennessee.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(k)
Sponsoring Witness: Valerie L. Scott

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission Form 1 (electric), Federal Energy Regulatory Commission Form 2 (gas), or Public Service Commission Form T (telephone).

Response:

LG&E's most recent FERC Form 1 and KPSC Annual Report for Major Natural Gas Companies for the year ended December 31, 2013, are attached. Please note that by a FERC Order dated July 12, 2007 in FERC Docket No. CP07-232-000, LG&E was granted a Section (7) exemption by the FERC under the Natural Gas Act, and as a part of that exemption LG&E was granted "a waiver of reporting and accounting requirements," which includes the filing of Form 2 with the FERC. In addition, on February 15, 2008, the Public Service Commission issued an order granting LG&E's request to cease the annual filing of the FERC Form 2. In lieu of filing a FERC Form 2 with the Public Service Commission, LG&E was ordered to file a paper copy of the annual report information that it files with the Public Service Commission electronically, and include with such copy a paper copy of the notes to its financial statements that LG&E had previously filed as part of its FERC Form 2.

THIS FILING IS	
Item 1: ☒ An Initial (Original) Submission	OR ☐ Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

Public Service Commission
of
Kentucky

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Louisville Gas and Electric Company	**End of** 2013/Q4

LOUISVILLE GAS AND ELECTRIC COMPANY

PUBLIC SERVICE COMMISSION OF KENTUCKY

PRINCIPAL PAYMENT AND INTEREST INFORMATION FOR THE YEAR ENDING DECEMBER 31, 2013

1. Amount of Principal Payment during calendar year $ 0.00

2. Is Principal current? (Yes) X (No) __________

3. Is Interest current? (Yes) X (No) __________

SERVICES PERFORMED BY INDEPENDENT CERTIFIED PUBLIC ACCOUNTANT

Are your financial statements examined by a Certified Public Accountant?

(Yes) X (No) __________

If yes, which service is performed?

Audit X

Compilation _________

Review _________

Please enclose a copy of the accountant's report with annual report.

LOUISVILLE GAS AND ELECTRIC COMPANY
ADDITIONAL INFORMATION TO BE FURNISHED WITH
2013 ANNUAL REPORT

ELECTRIC UTILITIES

Please furnish the following information, for Kentucky Operations only, and attach to your Annual Report:

Number of Rural Customers (Other than Farms)	INFORMATION NOT AVAILABLE
Number of Farms Served (A farm is any agricultural operating unit consisting of 3 acres or more)	INFORMATION NOT AVAILABLE
Number of KWH sold to all Rural Customers	INFORMATION NOT AVAILABLE
Total Revenue from all Rural Customers	INFORMATION NOT AVAILABLE

LINE DATA

Total number of Miles of Wire Energized (Located in Kentucky)	11,934
Total number of Miles of Pole line (Located in Kentucky)	7,222

Name of Counties in which you furnish Electric Service:
(If additional space is required, add additional sheet)

Bullitt, Hardin, Henry, Jefferson, Meade, Oldham, Shelby, Spencer and Trimble

(A) Based on Standard Industrial Classification (SIC) Major Groups 01 (Agricultural Production-Crops) and 02 (Agricultural Production Livestock and Animal Specialties).

Louisville Gas and Electric Company
Supplemental Electric Information
Revenues, Customers and KWH Sales
For Reporting Year 2013

	Revenues	KWHs Sold	Customers
440 Residential	$ 405,961,655	4,164,048,797	348,047
442 Commercial & Industrial Sales			
Small(or Commercial)	$ 329,906,063	3,685,168,515	42,062
Large (or Industrial)	$ 174,274,392	2,699,966,052	429
444 Public St. & Highway Lighting	$ 2,884,918	18,440,935	650
445 Other Sales to Public Authorities	$ 88,714,502	1,131,350,511	4,124
446 Sales to Railroads and Railways	$ -	-	-
448 Interdepartmental Sales	$ -	-	-
TOTAL Sales to Ultimate Customers	$1,001,741,530	11,698,974,810	395,312
447 Sales for Resale	$ 78,580,878	2,779,341,000	13
TOTAL Sales of Electricity	$1,080,322,408	14,478,315,810	395,325

THIS PAGE MUST BE COMPLETED AND RETURNED WITH THE ANNUAL REPORT

LOUISVILLE GAS AND ELECTRIC COMPANY
NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES
SUPPLEMENTAL INFORMATION TO 2013 ANNUAL REPORT

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.

The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1.	Payroll Period Ended (Date)	12/31/2013
2.	Total Regular Full-Time Employees	725
3.	Total Part-Time and Temporary Employees	6
4.	Total Employees	731

Additional Requested Information

Utility Name Louisville Gas and Electric Company

FEIN# (Federal Employer Identification Number)

6	1	-	0	2	6	4	1	5	0

Contact Person T. Eric Raible

Contact Person's E-Mail Address eric.raible@lge-ku.com

Utility's Web Address www.lge-ku.com

Please complete the above information, if it is available.

If there are multiple staff who may be contacts please include their names and e-mail addresses also.

THIS FILING IS

Item 1: ☒ An Initial (Original) Submission OR ☐ Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Louisville Gas and Electric Company	**End of** 2013/Q4

Building a better
working world

Ernst & Young LLP
Suite 2400
400 West Market Street
Louisville, KY 40202

Tel: +1 502 585 1400
Fax: +1 502 584 4221
ey.com

March 24, 2014

Kent Blake
Chief Financial Officer
LG&E & KU Energy LLC
220 West Main Street
Louisville, KY 40202

Dear Mr. Blake,

Enclosed please find copies of our manually signed reports on the regulatory-basis financial statements of Louisville Gas and Electric Company and Kentucky Utilities Company as of December 31, 2013 and 2012, and for the years then ended. Please retain this letter and the enclosures in your files as evidence of our authorization to include the attached reports in the 2013 Annual Form 1 filed with the Federal Energy Regulatory Commission.

If you have any questions regarding the form or use of this report, please call me.

Regards,

Ritu Furlan

Attachment

Report of Independent Auditors

To the Board of Directors and Stockholder of Louisville Gas and Electric Company:

We have audited the financial statements of Louisville Gas and Electric Company, which comprise the comparative balance sheet as of December 31, 2013 and 2012, and the related statements of income, retained earnings and cash flows for the years then ended and the related notes to the financial statements, included on pages 110 through 123.68 in the Federal Energy Regulatory Commission ("FERC") Form No. 1.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in conformity with the financial reporting provisions of the Uniform System of Accounts prescribed by the FERC described in Note 1; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free of material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities, and proprietary capital of Louisville Gas and Electric Company at December 31, 2013 and 2012, and its income and expenses and its cash flows for the years then ended, in accordance with the Uniform System of Accounts prescribed by the FERC described in Note 1.

Regulatory Basis of Accounting

As described in Note 1 to the financial statements, the financial statements have been prepared by Louisville Gas and Electric Company in accordance with the Uniform System of Accounts prescribed by the FERC, which is a basis of accounting other than U.S. generally accepted accounting principles to meet the requirements of the FERC. Our opinion is not modified with respect to this matter.

Restriction on Use

Our report is intended solely for the information and use of the FERC and is not intended to be and should not be used by anyone other than these specified parties.

Ernst & Young LLP

Louisville, Kentucky
March 24, 2014

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

BLANK

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Louisville Gas and Electric Company	02 Year/Period of Report End of 2013/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 220 West Main Street, Louisville, KY 40202	
05 Name of Contact Person T. Eric Raible	06 Title of Contact Person Mgr-Regulatory Acct & Reprt
07 Address of Contact Person *(Street, City, State, Zip Code)* 220 West Main Street, Louisville, KY 40202	

08 Telephone of Contact Person,*Including Area Code* (502) 627-3426	09 This Report Is (1) ☒ 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)* 03/24/2014
02 Title Chief Financial Officer		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	None
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	None
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	None
26	Transmission Service and Generation Interconnection Study Costs	231	None
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	
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	None

BLANK

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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

☒ No annual report to stockholders is prepared

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2013/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 July 2, 1913

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Respondent furnishes electric and natural gas services in the City of Louisville and adjacent territory in Kentucky.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ Yes...Enter the date when such independent accountant was initially engaged:
(2) ☒ No

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2013/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.

Louisville Gas and Electric Company (LG&E) 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
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	CURRENT OFFICERS AT DECEMBER 31, 2013		
2			
3	Chairman of the Board, President and		
4	Chief Executive Officer	Victor A. Staffieri	314,807
5	Chief Administrative Officer	S. Bradford Rives	160,909
6	General Counsel, Chief Compliance Officer and		
7	Corporate Secretary	Gerald A. Reynolds	113,460
8	Chief Financial Officer	Kent W. Blake	100,569
9	Chief Operating Officer	Paul W. Thompson	195,399
10			
11	FORMER OFFICER DURING 2013		
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13	Senior Vice President - Energy Delivery	Chris Hermann	56,753
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Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2013/Q4

FOOTNOTE DATA

Schedule Page: 104 Line No.: 4 Column: c

Officers are employed by LKS. Amounts shown reflect the portion of their salary allocated to LG&E.

Schedule Page: 104 Line No.: 9 Column: b

Paul W. Thompson, Senior Vice President – Energy Services, was named Chief Operating Officer, effective February 18, 2013.

Schedule Page: 104 Line No.: 13 Column: b

Chris Hermann, Senior Vice President - Energy Delivery, retired effective May 1, 2013.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	CURRENT BOARD OF DIRECTORS AT DECEMBER 31, 2013	
2		
3	Victor A. Staffieri, Chairman of the Board, President	
4	and Chief Executive Officer	220 West Main Street, Louisville, KY 40202
5	S. Bradford Rives, Chief Administrative Officer	220 West Main Street, Louisville, KY 40202
6	Paul W. Thompson, Chief Operating Officer	220 West Main Street, Louisville, KY 40202
7	Paul A. Farr, EVP and Chief Financial Officer of PPL	2 North Ninth Street, Allentown, PA 18101
8	William H. Spence, Chairman President and	
9	Chief Executive Officer of PPL	2 North Ninth Street, Allentown, PA 18101
10		
11	FORMER DIRECTOR DURING 2013	
12		
13	Chris Hermann, SVP - Energy Delivery	220 West Main Street, Louisville, KY 40202
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 105 Line No.: 6 Column: a

Paul W. Thompson, Senior Vice President – Energy Services, was named Chief Operating Officer, effective February 18, 2013.

Schedule Page: 105 Line No.: 13 Column: a

Chris Hermann, Senior Vice President - Energy Delivery, retired effective May 1, 2013.

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Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

☒ Yes
☐ No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Open Access Transmission Tariff (OATT)	
2	Attachment O	Docket No. ER11-2955
3		
4	OATT Schedule 1	Docket No. ER10-1509
5		
6		
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Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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)?

☐ 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
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Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	Page 3 of 5	Schedule 10	3	1
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 1062 Line No.: 2 Column: b

Transmission Operation and Maintenance expenses exclude the amortization of certain regulatory assets approved by the KPSC only.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report / /	Year/Period of Report End of 2013/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.

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Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None.

2. None.

3. None.

4. None of a material nature.

5. None.

6. LG&E issued long-term first mortgage bonds totaling $250 million on November 14, 2013. The bonds mature in November 2043 and have an interest rate of 4.65%. This transaction was approved by the KPSC on August 3, 2012, in Case No. 2012-00233. LG&E received FERC authorization in FERC Docket No. ES13-54-000 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, 2015. LG&E's money pool balance was zero at December 31, 2013, and December 31, 2012, respectively. LG&E established a commercial paper program in February 2012, allowing issuance of up to $250 million. The program was increased to $350 million effective April 1, 2013. As of December 31, 2013, and December 31, 2012, the outstanding commercial paper balance is $20 million and $55 million, respectively.

7. None.

8. During the first quarter of 2013, exempt and non-exempt employees received routine wage increases in accordance with annual salary reviews. As outlined in the IBEW Local 2100 contract, union employees received a negotiated wage increase effective November 11, 2013.

9. See Notes 4 and 10 of Notes to Financial Statements on page 123.

10. None.

11. N/A

12. See Notes to Financial Statements on page 123.

13. On January 31, 2013, Chris Hermann, Senior Vice President – Energy Delivery, announced his retirement, effective May 1, 2013, and Paul W. Thompson, Senior Vice President – Energy Services, was named Chief Operating Officer, effective February 18, 2013. Effective February 18, 2013, Lonnie E. Bellar was named Vice President—Gas Distribution; John P. Malloy, Vice President—Customer Services; Edwin R. Staton, Vice President—State Regulation and Rates and P. Gregory Thomas, Vice President—Electric Distribution. Effective March 7, 2013, Thomas A. Jessee was named Vice President—Transmission.

14. LG&E is a participant in a cash pooling arrangement, but its proprietary capital ratio is above 30 percent.

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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	5,067,913,274	4,881,636,687
3	Construction Work in Progress (107)	200-201	651,432,116	258,364,758
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,719,345,390	5,140,001,445
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,304,132,232	2,201,756,057
6	Net Utility Plant (Enter Total of line 4 less 5)		3,415,213,158	2,938,245,388
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)		3,415,213,158	2,938,245,388
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		2,139,990	2,139,990
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		552,781	592,759
19	(Less) Accum. Prov. for Depr. and Amort. (122)		63,360	65,709
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	594,286	594,286
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		22,225,512	31,747,624
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)		23,309,219	32,868,960
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		3,467,771	7,372,093
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		20,090	20,090
38	Temporary Cash Investments (136)		4,534,363	14,316,601
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		102,699,981	60,348,949
41	Other Accounts Receivable (143)		9,932,099	16,119,508
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,828,849	1,218,026
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		108,735	13,662,418
45	Fuel Stock (151)	227	64,191,758	61,099,619
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	35,816,745	32,727,610
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	41,739	1,771

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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	6,186,832	5,860,024
55	Gas Stored Underground - Current (164.1)		47,546,888	42,010,154
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		5,125,670	6,976,761
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		25,490	28,358
60	Rents Receivable (172)		536,817	332,546
61	Accrued Utility Revenues (173)		85,152,363	72,143,278
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		0	7,142,276
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)		363,558,492	338,944,030
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		10,857,401	9,831,700
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	316,510,769	413,428,343
73	Prelim. Survey and Investigation Charges (Electric) (183)		561,651	1,567,192
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	503,728,950	527,590,338
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		18,442,649	19,968,045
82	Accumulated Deferred Income Taxes (190)	234	174,804,497	163,506,960
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,024,905,917	1,135,892,578
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,829,126,776	4,448,090,946

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 110 Line No.: 63 Column: c

Decrease in balance related to settlement of interest rate swaps during September 2013.

Schedule Page: 110 Line No.: 69 Column: c

Unamortized Debt Expenses (181) Without Purchase Accounting	$ 13,965,458
Purchase Accounting Adjustment	(3,108,057)
Total for Unamortized Debt Expenses (181)	$ 10,857,401

Schedule Page: 110 Line No.: 69 Column: d

Unamortized Debt Expenses (181) Without Purchase Accounting	$ 13,126,318
Purchase Accounting Adjustment	(3,294,618)
Total for Unamortized Debt Expenses (181)	$ 9,831,700

Schedule Page: 110 Line No.: 72 Column: c

Other Regulatory Assets (182.3) Without Purchase Accounting	$ 312,656,793
Purchase Accounting Adjustment	3,853,976
Total for Other Regulatory Assets (182.3)	$ 316,510,769

Schedule Page: 110 Line No.: 72 Column: d

Other Regulatory Assets (182.3) Without Purchase Accounting	$ 408,462,227
Purchase Accounting Adjustment	4,966,116
Total for Other Regulatory Assets (182.3)	$ 413,428,343

Schedule Page: 110 Line No.: 78 Column: c

Miscellaneous Deferred Debits (186) Without Purchase Accounting	$ 932,344
Purchase Accounting Adjustment	502,796,606
Total for Miscellaneous Deferred Debits (186)	$ 503,728,950

Schedule Page: 110 Line No.: 78 Column: d

Miscellaneous Deferred Debits (186) Without Purchase Accounting	$ 374,817
Purchase Accounting Adjustment	527,215,521
Total for Miscellaneous Deferred Debits (186)	$ 527,590,338

Schedule Page: 110 Line No.: 82 Column: c

Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$ 130,998,532
Purchase Accounting Adjustment	43,805,965
Total for Accumulated Deferred Income Taxes (190)	$ 174,804,497

Schedule Page: 110 Line No.: 82 Column: d

Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$ 106,846,806
Purchase Accounting Adjustment	56,660,154
Total for Accumulated Deferred Income Taxes (190)	$ 163,506,960

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COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	425,170,424	425,170,424
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	1,363,667,368	1,277,667,368
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	835,889	835,889
11	Retained Earnings (215, 215.1, 216)	118-119	172,457,991	108,052,874
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	0
16	Total Proprietary Capital (lines 2 through 15)		1,960,459,894	1,810,054,777
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,359,304,000	1,109,304,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	-1,773,437	5,926,259
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		4,901,231	3,388,598
24	Total Long-Term Debt (lines 18 through 23)		1,352,629,332	1,111,841,661
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)		4,329,048	5,122,022
29	Accumulated Provision for Pensions and Benefits (228.3)		95,101,935	186,312,334
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		32,206,463	29,497,733
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	24,093,417
34	Asset Retirement Obligations (230)		82,196,215	64,684,737
35	Total Other Noncurrent Liabilities (lines 26 through 34)		213,833,661	309,710,243
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		19,996,778	54,992,670
38	Accounts Payable (232)		170,850,243	121,578,266
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		24,294,741	22,801,659
41	Customer Deposits (235)		24,075,549	23,464,189
42	Taxes Accrued (236)	262-263	11,474,666	1,735,495
43	Interest Accrued (237)		5,580,258	5,118,488
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,419,912	1,309,572
48	Miscellaneous Current and Accrued Liabilities (242)		18,912,401	19,168,503
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		35,912,921	30,990,202
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		32,206,463	29,497,733
52	Derivative Instrument Liabilities - Hedges (245)		0	27,615,282
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	24,093,417
54	Total Current and Accrued Liabilities (lines 37 through 53)		280,311,006	255,183,176
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		6,748,025	6,709,975
57	Accumulated Deferred Investment Tax Credits (255)	266-267	37,770,885	39,871,227
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	17,863,555	9,080,813
60	Other Regulatory Liabilities (254)	278	206,203,422	194,283,183
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)		598,895,367	535,869,973
64	Accum. Deferred Income Taxes-Other (283)		154,411,629	175,485,918
65	Total Deferred Credits (lines 56 through 64)		1,021,892,883	961,301,089
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,829,126,776	4,448,090,946

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 112 Line No.: 7 Column: c

Other Paid-in Capital (208-211) Without Purchase Accounting	$	169,581,499
Purchase Accounting Adjustment		1,194,085,869
Total for Other Paid-in Capital (208-211)	$	1,363,667,368

Schedule Page: 112 Line No.: 7 Column: d

Other Paid-in Capital (208-211) Without Purchase Accounting	$	83,581,499
Purchase Accounting Adjustment		1,194,085,869
Total for Other Paid-in Capital (208-211)	$	1,277,667,368

Schedule Page: 112 Line No.: 11 Column: c

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$	976,302,939
Purchase Accounting Adjustment in accordance with Docket No. AC11-83-000		(808,946,891)
Amortization of Purchase Accounting Adjustment - pollution control bonds (net of deferred taxes of $3,248,211)		5,101,944
Rounding		(1)
Total for Retained Earnings (215, 215.1, 216)	$	172,457,991

As of December 31, 2013, in compliance with FERC 305 Filing in 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 12/31/2013 -- sum of lines 11 & 12 on page 112 (Retained Earnings and Unappropriated Undistributed Subsidiary Earnings)	$	172,457,991
Add: Stated capital account, reflecting pre-acquisition retained earnings less dividends applied to the account -- tracked in a separate purchase accounting general ledger -- a component of the amount on line 7 on page 112 (Other Paid-In Capital)		808,946,891
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)		(5,101,944)
Rounding		1
Retained earnings as of 12/31/2013, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$	976,302,939

Retained earnings prior to the 11/1/2010 acquisition		808,946,891
Cumulative post-acquisition net income		424,856,048
Cumulative post-acquisition dividends		(257,500,000)
Retained earnings as of 12/31/2013, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$	976,302,939

Schedule Page: 112 Line No.: 11 Column: d

Retained Earnings (215, 215.1, 216) Without Purchase Accounting	$	916,602,335
Purchase Accounting Adjustment in accordance with Docket No. AC11-83-000		(808,946,891)
Amortization of Purchase Accounting Adjustment -		

pollution control bonds (net of deferred taxes of $253,029)		397,430
Total for Retained Earnings (215, 215.1, 216)	$	108,052,874

As of December 31, 2012, in compliance with FERC 305 Filing in 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 12/31/2012 -- sum of lines 11 & 12 on page 112 (Retained Earnings and Unappropriated Undistributed Subsidiary Earnings)	$	108,052,874
Add: Stated capital account, reflecting pre-acquisition retained earnings less dividends applied to the account -- tracked in a separate purchase accounting general ledger -- a component of the amount on line 7 on page 112 (Other Paid-In Capital)		808,946,891
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)		(397,430)
Retained earnings as of 12/31/2012, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$	916,602,335

Retained earnings prior to the 11/1/2010 acquisition	$	808,946,891
Cumulative post-acquisition net income		266,155,444
Cumulative post-acquisition dividends		(158,500,000)
Retained earnings as of 12/31/2012, adjusted to remove the affects of push-down accounting ("adjusted retained earnings")	$	916,602,335

Schedule Page: 112 Line No.: 21 Column: c

Remarketed bonds related to purchase accounting were eliminated during the fourth quarter of 2013 leaving one bond with a negative fair market value.

Other Long-Term Debt (224) Without Purchase Accounting	$	-
Purchase Accounting Adjustment		(1,773,437)
Total for Other Long-Term Debt (224)	$	(1,773,437)

Schedule Page: 112 Line No.: 21 Column: d

Other Long-Term Debt (224) Without Purchase Accounting	$	-
Purchase Accounting Adjustment		5,926,259
Total for Other Long-Term Debt (224)	$	5,926,259

Schedule Page: 112 Line No.: 33 Column: c

In December 2013, Long-Term Derivative Liability was reclassed from Derivative Liability Hedges (245) to Derivative Liability (244) for proper FERC presentation.

Schedule Page: 112 Line No.: 34 Column: c

AROs were revalued primarily due to updates in the estimated cash flows for ash ponds and CCR surface impoundments based on updated cost estimates.

Schedule Page: 112 Line No.: 52 Column: c

In December 2013, Long-Term Derivative Liability was reclassed from Derivative Liability Hedges (245) to Derivative Liability (244) for proper FERC presentation.

Schedule Page: 112 Line No.: 53 Column: c

In December 2013, Long-Term Derivative Liability was reclassed from Derivative Liability

BLANK

Hedges (245) to Derivative Liability (244) for proper FERC presentation.

Schedule Page: 112 Line No.: 59 Column: c

Other Deferred Credits (253) Without Purchase Accounting	$	17,117,636
Purchase Accounting Adjustment		745,919
Total for Other Deferred Credits (253)	$	17,863,555

Schedule Page: 112 Line No.: 59 Column: d

Other Deferred Credits (253) Without Purchase Accounting	$	7,409,316
Purchase Accounting Adjustment		1,671,497
Total for Other Deferred Credits (253)	$	9,080,813

Schedule Page: 112 Line No.: 60 Column: c

Other Regulatory Liabilities (254) Without Purchase Accounting	$	92,564,168
Purchase Accounting Adjustment		113,639,254
Total for Other Regulatory Liabilities (254)	$	206,203,422

Schedule Page: 112 Line No.: 60 Column: d

Other Regulatory Liabilities (254) Without Purchase Accounting	$	56,225,014
Purchase Accounting Adjustment		138,058,169
Total for Other Regulatory Liabilities (254)	$	194,283,183

Schedule Page: 112 Line No.: 64 Column: c

Accumulated Deferred Income Taxes - Other (283) Without Purchase Accounting	$	109,915,797
Purchase Accounting Adjustment		44,495,832
Total for Accumulated Deferred Income Taxes - Other (283)	$	154,411,629

Schedule Page: 112 Line No.: 64 Column: d

Accumulated Deferred Income Taxes - Other (283) Without Purchase Accounting	$	121,131,078
Purchase Accounting Adjustment		54,354,840
Total for Accumulated Deferred Income Taxes - Other (283)	$	175,485,918

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,420,817,715	1,323,624,802		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	831,716,786	784,377,726		
5	Maintenance Expenses (402)	320-323	113,413,021	118,770,589		
6	Depreciation Expense (403)	336-337	139,714,329	143,303,463		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337		2,987,801		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	7,948,703	8,836,853		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)			5,915,937		
14	Taxes Other Than Income Taxes (408.1)	262-263	32,517,048	31,025,991		
15	Income Taxes - Federal (409.1)	262-263	53,107,974	-596,880		
16	- Other (409.1)	262-263	16,078,249	2,588,533		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	211,251,945	179,830,059		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	183,189,299	108,743,665		
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,100,342	-2,847,617		
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)		282	694		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)			2,928,136		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,220,458,132	1,156,544,358		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		200,359,583	167,080,444		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,096,596,441	1,069,346,403	324,221,274	254,278,399			2
						3
625,928,383	625,687,117	205,788,403	158,690,609			4
95,645,484	97,601,940	17,767,537	21,168,649			5
115,965,636	122,107,548	23,748,693	21,195,915			6
	1,935,439		1,052,362			7
5,643,550	6,274,166	2,305,153	2,562,687			8
						9
						10
						11
						12
	3,698,637		2,217,300			13
25,031,903	23,824,390	7,485,145	7,201,601			14
41,181,745	6,048,731	11,926,229	-6,645,611			15
13,122,319	2,414,625	2,955,930	173,908			16
167,982,718	139,505,829	43,269,227	40,324,230			17
148,438,529	88,200,893	34,750,770	20,542,772			18
-1,987,122	-2,721,997	-113,220	-125,620			19
						20
						21
282	694					22
						23
	1,763,198		1,164,938			24
940,075,805	932,540,762	280,382,327	224,003,596			25
156,520,636	136,805,641	43,838,947	30,274,803			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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)		200,359,583	167,080,444		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		45,217	13,925		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		36,633	25,335		
33	Revenues From Nonutility Operations (417)		1,265,429	1,267,144		
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)		117,128	186,894		
38	Allowance for Other Funds Used During Construction (419.1)					
39	Miscellaneous Nonoperating Income (421)		234	8,526		
40	Gain on Disposition of Property (421.1)		16,540	122,175		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		1,407,915	1,573,329		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		12,001			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		2,618,802	2,259,050		
46	Life Insurance (426.2)					
47	Penalties (426.3)		297,610	227,857		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		986,880	886,758		
49	Other Deductions (426.5)		1,404,757	1,037,367		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,320,050	4,411,032		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	5,960	3,564		
53	Income Taxes-Federal (409.2)	262-263	-1,255,593	-977,712		
54	Income Taxes-Other (409.2)	262-263	-192,086	406,552		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	205,595	740		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	19,165	219,065		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,255,289	-785,921		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-2,656,846	-2,051,782		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		28,812,421	36,698,051		
63	Amort. of Debt Disc. and Expense (428)		2,906,102	2,072,123		
64	Amortization of Loss on Reaquired Debt (428.1)		1,048,550	1,230,292		
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)		10,061	3,429		
68	Other Interest Expense (431)		1,520,486	1,918,559		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)					
70	Net Interest Charges (Total of lines 62 thru 69)		34,297,620	41,922,454		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		163,405,117	123,106,208		
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)		163,405,117	123,106,208		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 114 Line No.: 7 Column: c

In August 2013, year-to-date regulatory offsets for depreciation on asset retirement cost assets were reclassed from Regulatory Credits (407.4) to Depreciation Expense on Asset Retirement Costs (403.1).

Schedule Page: 114 Line No.: 7 Column: g

In August 2013, year-to-date regulatory offsets for depreciation on asset retirement cost assets were reclassed from Regulatory Credits (407.4) to Depreciation Expense on Asset Retirement Costs (403.1).

Schedule Page: 114 Line No.: 7 Column: i

In August 2013, year-to-date regulatory offsets for depreciation on asset retirement cost assets were reclassed from Regulatory Credits (407.4) to Depreciation Expense on Asset Retirement Costs (403.1).

Schedule Page: 114 Line No.: 13 Column: c

In August 2013, year-to-date regulatory offsets for depreciation on asset retirement cost assets and ARO liability accretion were reclassed from Regulatory Credits (407.4) to Depreciation Expense on Asset Retirement Costs (403.1) and Accretion Expense (411.10).

Schedule Page: 114 Line No.: 13 Column: g

In August 2013, year-to-date regulatory offsets for depreciation on asset retirement cost assets and ARO liability accretion were reclassed from Regulatory Credits (407.4) to Depreciation Expense on Asset Retirement Costs (403.1) and Accretion Expense (411.10).

Schedule Page: 114 Line No.: 13 Column: i

In August 2013, year-to-date regulatory offsets for depreciation on asset retirement cost assets and ARO liability accretion were reclassed from Regulatory Credits (407.4) to Depreciation Expense on Asset Retirement Costs (403.1) and Accretion Expense (411.10).

Schedule Page: 114 Line No.: 15 Column: d

The federal income tax expense decreased in 2012 primarily due to temporary differences for bonus depreciation and pension payments. The reconciliation of reported net income with taxable income for federal income taxes on Schedule Page: 261 provides further details.

Schedule Page: 114 Line No.: 17 Column: c

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 197,171,593
Amortization of Purchase Accounting Adjustment	14,080,352
Total for Provision for Deferred Income Taxes (410.1)	$ 211,251,945

Schedule Page: 114 Line No.: 17 Column: d

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 168,167,325
Amortization of Purchase Accounting Adjustment	11,662,734
Total for Provision for Deferred Income Taxes (410.1)	$ 179,830,059

Schedule Page: 114 Line No.: 17 Column: g

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 154,549,526
Amortization of Purchase Accounting Adjustment	13,433,192
Total for Provision for Deferred Income Taxes (410.1)	$ 167,982,718

Schedule Page: 114 Line No.: 17 Column: h

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 127,982,502
Amortization of Purchase Accounting Adjustment	11,523,327
Total for Provision for Deferred Income Taxes (410.1)	$ 139,505,829

Schedule Page: 114 Line No.: 17 Column: i

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 42,622,067

Amortization of Purchase Accounting Adjustment	647,160
Total for Provision for Deferred Income Taxes (410.1)	$ 43,269,227

Schedule Page: 114 Line No.: 17 Column: j

Provision for Deferred Income Taxes (410.1) Without Purchase Accounting	$ 40,184,823
Amortization of Purchase Accounting Adjustment	139,407
Total for Provision for Deferred Income Taxes (410.1)	$ 40,324,230

Schedule Page: 114 Line No.: 18 Column: c

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 172,104,129
Amortization of Purchase Accounting Adjustment	11,085,170
Total for Provision for Deferred Income Taxes (411.1)	$ 183,189,299

Schedule Page: 114 Line No.: 18 Column: d

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 97,197,715
Amortization of Purchase Accounting Adjustment	11,545,950
Total for Provision for Deferred Income Taxes (411.1)	$ 108,743,665

Schedule Page: 114 Line No.: 18 Column: g

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 137,386,506
Amortization of Purchase Accounting Adjustment	11,052,023
Total for Provision for Deferred Income Taxes (411.1)	$ 148,438,529

Schedule Page: 114 Line No.: 18 Column: h

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 76,770,409
Amortization of Purchase Accounting Adjustment	11,430,484
Total for Provision for Deferred Income Taxes (411.1)	$ 88,200,893

Schedule Page: 114 Line No.: 18 Column: i

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 34,717,623
Amortization of Purchase Accounting Adjustment	33,147
Total for Provision for Deferred Income Taxes (411.1)	$ 34,750,770

Schedule Page: 114 Line No.: 18 Column: j

Provision for Deferred Income Taxes (411.1) Without Purchase Accounting	$ 20,427,306
Amortization of Purchase Accounting Adjustment	115,466
Total for Provision for Deferred Income Taxes (411.1)	$ 20,542,772

Schedule Page: 114 Line No.: 24 Column: c

In August 2013, year-to-date regulatory offsets for ARO liability accretion were reclassed from Regulatory Credits (407.4) to Accretion Expense (411.10).

Schedule Page: 114 Line No.: 24 Column: g

In August 2013, year-to-date regulatory offsets for ARO liability accretion were reclassed from Regulatory Credits (407.4) to Accretion Expense (411.10).

Schedule Page: 114 Line No.: 24 Column: i

In August 2013, year-to-date regulatory offsets for ARO liability accretion were reclassed from Regulatory Credits (407.4) to Accretion Expense (411.10).

Schedule Page: 114 Line No.: 54 Column: d

This amount is the result of an increase in state tax due to an ASC 740-10 reserve for LG&E's recycle credit recorded in 2012.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 114 Line No.: 62 Column: c

Interest on Long-Term Debt (427) Without Purchase Accounting	$	36,512,116
Amortization of Purchase Accounting Adjustment		(7,699,695)
Total for Interest on Long-Term Debt (427)	$	28,812,421

Schedule Page: 114 Line No.: 62 Column: d

Interest on Long-Term Debt (427) Without Purchase Accounting	$	36,998,263
Amortization of Purchase Accounting Adjustment		(300,212)
Total for Interest on Long-Term Debt (427)	$	36,698,051

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		108,052,874	60,196,667
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		163,405,117	123,106,208
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				(1)
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			(1)
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		-99,000,000	(75,250,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-99,000,000	(75,250,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		172,457,991	108,052,874
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		172,457,991	108,052,874
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

BLANK

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 118   Line No.: 48   Column: c

See footnote data detail on Schedule Page: 112, Line No.: 11, Column: c.

Schedule Page: 118   Line No.: 48   Column: d

See footnote 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
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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)	163,405,117	123,106,208
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	139,714,329	146,291,264
5	Amortization of Plant	7,948,703	8,836,853
6			
7			
8	Deferred Income Taxes (Net)	27,658,386	74,324,470
9	Investment Tax Credit Adjustment (Net)	-2,100,342	-2,847,617
10	Net (Increase) Decrease in Receivables	-32,386,979	-11,426,875
11	Net (Increase) Decrease in Inventory	-12,325,357	404,431
12	Net (Increase) Decrease in Allowances Inventory	-39,968	741
13	Net Increase (Decrease) in Payables and Accrued Expenses	-31,719,957	-8,686,827
14	Net (Increase) Decrease in Other Regulatory Assets	46,439,594	-11,349,950
15	Net Increase (Decrease) in Other Regulatory Liabilities	85,664,526	-2,392,582
16	(Less) Allowance for Other Funds Used During Construction		
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-46,549,895	-11,040,844
19	Change in Other Deferred Debits	348,774	-131,988
20	Change in Other Deferred Credits	9,819,725	2,325,630
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	355,876,656	307,412,914
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-539,449,786	-255,358,235
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	-23,308,315	-16,238,636
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction		
31	Other (provide details in footnote):	-13,869,115	-14,215,736
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-576,627,216	-285,812,607
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	32,680	124,800
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Change in Restricted Cash	9,522,111	-2,888,616
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-567,072,425	-288,576,423
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	245,509,209	-1,826,861
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	-35,000,000	54,975,515
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	210,509,209	53,148,654
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	86,000,000	
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-99,000,000	-75,250,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	197,509,209	-22,101,346
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-13,686,560	-3,264,855
87			
88	Cash and Cash Equivalents at Beginning of Period	21,688,694	24,953,549
89			
90	Cash and Cash Equivalents at End of period	8,002,134	21,688,694

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 18 Column: b

Other operating cash flows:

Other changes in Net Utility Plant	$ (8,714,274)
Accumulated Provision for Uncollectible Accounts - Credit	(1,761,513)
Amortization of Debt Expenses and Losses on Bonds	3,377,048
Unamortized Discount on Long-Term Debt - Debit	287,367
Unamortized Discount on Short-Term Debt - Debit	4,108
Net decrease in Nonutility Property - Less Reserve	37,630
Net decrease in Prepayments and other assets	8,965,727
Net decrease in Preliminary Survey	447,889
Net increase in Customer Advances for Construction	38,050
Net increase in Asset Retirement Obligations	17,511,478
Net decrease in the Provision for Pension and Postretirement Benefits	(50,188,847)
Pension and Postretirement Funding	(47,674,773)
Net decrease in Other Liabilities	43,445,931
Reserve for Depreciation	(7,621,203)
Change in Deferred Income Taxes - purchase accounting	2,995,182
Change in Pollution Control Bonds - purchase accounting	(7,699,696)
Rounding	1
Total	$(46,549,895)

Schedule Page: 120 Line No.: 18 Column: c

Other operating cash flows:

Other changes in Net Utility Plant	$ (3,794,658)
Accumulated Provision for Uncollectible Accounts - Credit	(1,817,792)
Amortization of Debt Expenses and Losses on Bonds	3,022,555
Unamortized Discount on Long-Term Debt - Debit	279,860
Unamortized Discount on Short-Term Debt - Debit	17,155
Net increase in Nonutility Property - Less Reserve	(475,192)
Net increase in Prepayments and Other Assets	(8,809,619)
Net increase in Preliminary Survey	(256,992)
Net decrease in Customer Advances for Construction	(597,193)
Net increase in Asset Retirement Obligations	6,078,387
Net increase in the Provision for Pension and Postretirement Benefits	23,667,822
Pension and Postretirement Funding	(27,223,400)
Net decrease in Other Liabilities	1,935,735
Reserve for Depreciation	(2,884,081)
Change in Deferred Income Taxes - purchase accounting	116,782
Change in Pollution Control Bonds - purchase accounting	(300,212)
Rounding	(1)
Total	$(11,040,844)

Schedule Page: 120 Line No.: 31 Column: b

Other plant investing cash flows:

Costs incurred related to Asset Retirement Obligations	$(13,869,115)

Schedule Page: 120 Line No.: 31 Column: c

Other plant investing cash flows:

Costs incurred related to Asset Retirement Obligations	$(14,215,736)

Schedule Page: 120 Line No.: 76 Column: b

Other financing cash flows:

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

LG&E and KU Energy LLC Equity Contribution	$ 86,000,000

Schedule Page: 120 Line No.: 90 Column: b

Cash and cash equivalents are comprised of the following amounts:

Cash (131)	$ 3,467,771
Temporary Cash Investments (136)	4,534,363
Total Cash and Cash Equivalents at the End of Period	$ 8,002,134

Schedule Page: 120 Line No.: 90 Column: c

Cash and cash equivalents are comprised of the following amounts:

Cash (131)	$ 7,372,093
Temporary Cash Investments (136)	14,316,601
Total Cash and Cash Equivalents at the End of Period	$ 21,688,694

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report / /	Year/Period of Report End of 2013/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

GLOSSARY OF TERMS AND ABBREVIATIONS

KU **-** Kentucky Utilities Company, a public utility subsidiary of LKE engaged in the regulated generation, transmission, distribution and sale of electricity, primarily in Kentucky.

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 services to LKE and its subsidiaries.

PPL **-** PPL Corporation, the parent holding company of LKE and other subsidiaries.

Other terms and abbreviations

401(h) account **-** A sub-account established within a qualified pension trust to provide for the payment of retiree medical costs.

AOCI **-** accumulated other comprehensive income or loss.

ARO **-** asset retirement obligation.

BREC **-** Big Rivers Electric Corporation, a power-generating rural electric cooperative in western Kentucky.

Cane Run Unit 7 **-** a natural gas combined-cycle unit under construction in Kentucky, jointly owned by LG&E and KU, which is expected to provide additional electric generating capacity of 640 MW (141 MW and 499 MW to LG&E and KU) in 2015.

CAIR **-** the EPA's Clean Air Interstate Rule.

CCR **-** Coal Combustion Residuals. 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.

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.

CSAPR **-** Cross-State Air Pollution Rule.

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2013/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Dodd-Frank Act **-** the Dodd-Frank Wall Street Reform and Consumer Protection Act that was signed into law in July 2010.

DSM **-** Demand Side Management. Pursuant to Kentucky Revised Statute 278.285, the KPSC may determine the reasonableness of DSM plans proposed by any utility under its jurisdiction. Proposed DSM mechanisms may seek full recovery of costs and revenues lost by implementing DSM programs and/or incentives designed to provide financial rewards to the utility for implementing cost-effective DSM programs. The cost of such programs shall be assigned only to the class or classes of customers which benefit from the programs.

EBPB **-** Employee Benefit Plan Board. The administrator of PPL's qualified retirement plans, which is charged with the fiduciary responsibility to oversee and manage those plans and the investments associated with those plans.

ECR **-** Environmental Cost Recovery. Pursuant to Kentucky Revised Statute 278.183, 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.

EPA **-** Environmental Protection Agency, a U.S. government agency.

E.W. Brown **-** a generating station in Kentucky with capacity of 1,594 MW.

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.

Fitch **-** Fitch, Inc., a credit rating agency.

GAAP **-** Generally Accepted Accounting Principles in the U.S.

GHG **-** greenhouse gas(es).

GLT **-** Gas Line Tracker. The KPSC approved LG&E's recovery of costs associated with gas service lines, gas risers, leak mitigation, and gas main replacements. Rate recovery became effective January 1, 2013.

Green River Unit 5 **-** a natural gas combined-cycle unit proposed to be built in Kentucky, jointly owned by LG&E and KU, which is expected to provide additional electric generating capacity of 700MW (280 MW and 420 MW to LG&E and KU) in 2018.

IBEW – International Brotherhood of Electrical Workers

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.

kWh **-** kilowatt-hour, basic unit of electrical energy.

LG&E 2010 Mortgage Indenture **-** LG&E's indenture, dated as of October 1, 2010, to The Bank of New York Mellon, as trustee, as supplemented.

LIBOR **-** London Interbank Offered Rate.

MATS **-** Mercury and Air Toxics Standards.

Moody's **-** Moody's Investors Service, Inc., a credit rating agency.

MW **-** megawatt, one thousand kilowatts.

MWh **-** megawatt-hour, one thousand kilowatt-hours.

NERC **-** North American Electric Reliability Corporation.

NGCC **-** Natural gas-fired combined-cycle turbine.

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 LKE indirectly owns an 8.13% interest (consists of LG&E's 5.63% and KU's 2.50% interests), which is accounted for as a cost-method investment. OVEC owns and operates two coal-fired power plants, the Kyger Creek plant in Ohio and the Clifty Creek plant in Indiana, with combined summer rating capacities of 2,120 MW.

PJM **-** PJM Interconnection, L.L.C., operator of the electricity transmission network and electric energy market in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

PP&E **-** property, plant and equipment.

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.

S&P **-** Standard & Poor's Ratings Services, a credit rating agency.

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.

***TC2* -** Trimble County Unit 2, a coal-fired plant located in Kentucky with a net summer capacity of 732 MW. LKE indirectly owns a 75% interest (consists of LG&E's 14.25% and KU's 60.75% interests) in TC2, or 549 MW of the capacity.

***Tolling agreement* -** agreement whereby the owner of an electricity generating facility agrees to use that facility to convert fuel provided by a third party into electricity for delivery back to the third party.

***VEBA* -** Voluntary Employee Benefit Association Trust, accounts for health and welfare plans for future benefit payments for employees, retirees or their beneficiaries.

***VIE* -** variable interest entity.

***Volumetric risk* -** the risk that the actual load volumes provided under full-requirement arrangements could vary significantly from forecasted volumes.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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As permitted by the FERC for the Year Ended December 31, 2013 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, 2013, which was filed with the SEC on February 24, 2014. Accordingly, these Notes do not reflect updated information since this filing date.

NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

General

Capitalized terms and abbreviations appearing in the notes to financial statements are defined in the glossary. Dollars are in millions, unless otherwise noted.

Business and Consolidation

LG&E is engaged in the regulated generation, transmission, distribution and sale of electricity. LG&E also engages in the regulated distribution and sale of natural gas.

The financial statements of LG&E include the company's own accounts as well as the accounts of all entities in which the company has a controlling financial interest. Entities for which a controlling financial interest is not demonstrated through voting interests are evaluated based on accounting guidance for VIEs. LG&E has no controlling interest in a VIE. Investments in entities in which a company has the ability to exercise significant influence but does not have a controlling financial interest are accounted for under the equity method. All other investments are carried at cost or fair value. All significant intercompany transactions have been eliminated. Any noncontrolling interests are reflected in the financial statements.

The financial statements of LG&E include its share of any undivided interests in jointly owned facilities, as well as its share of the related operating costs of those facilities. See Note 9 for additional information.

Regulation

LG&E is a cost-based rate-regulated utility for which rates are set by regulators to enable LG&E to recover the costs of providing electric or gas service and to provide a reasonable return to shareholders. Rates are generally established based on a test period adjusted to exclude unusual or nonrecurring items. As a result, the financial statements are subject to the accounting for certain types of regulation as prescribed by GAAP and reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery of underlying costs is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise currently be charged to expense. Regulatory liabilities are recognized for amounts expected to be returned through future regulated customer rates. In certain cases, regulatory liabilities are recorded based on an understanding or agreement with the regulator that rates have been set to recover costs that are expected to be incurred in the future, and the regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. The accounting for regulatory assets and 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

The system of accounts for LG&E is maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the applicable state regulatory commissions.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Loss Accruals

Potential losses are accrued when (1) information is available that indicates it is "probable" that a loss has been incurred, given the likelihood of the uncertain future events and (2) the amount of the loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." LG&E continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events. Loss accruals for environmental remediation are discounted when appropriate.

The accrual of contingencies that might result in gains is not recorded, unless realization is assured.

Price Risk Management

Energy and energy-related contracts are used to hedge the variability of expected cash flows associated with the generating units and marketing activities. Interest rate contracts are used to hedge exposures to changes in the fair value of debt instruments and to hedge exposures to variability in expected cash flows associated with existing 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 energy and energy-related contracts meet the definition of a derivative, while others do 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 energy contracts have been excluded from the requirements of derivative accounting treatment because NPNS has been elected. These contracts are accounted for using accrual accounting. All other contracts that have been classified as derivative contracts are reflected on the Balance Sheets at fair value. These contracts are recorded as "Price risk management assets" and "Price risk management liabilities" on the Balance Sheets. 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."

Energy and energy-related contracts are assigned a strategy and accounting classification. Processes exist that allow for subsequent review and validation of the contract information. See Note 14 for more information. The accounting department provides the traders and the risk management department with guidelines on appropriate accounting classifications for various contract types and strategies. Some examples of these guidelines include, but are not limited to:

- Physical coal, limestone, lime, uranium, electric transmission, gas transportation, gas storage and renewable energy credit contracts not traded on an exchange are not derivatives due to the lack of net settlement provisions.

- Only contracts where physical delivery is deemed probable throughout the entire term of the contract can qualify for NPNS.

- Physical transactions that permit cash settlement and financial transactions do not qualify for NPNS because physical delivery cannot be asserted; however, these transactions can receive cash flow hedge treatment if they effectively hedge the volatility in the future cash flows for energy-related commodities.

- Certain purchased option contracts or net purchased option collars may receive cash flow hedge treatment.

- Derivative transactions that do not qualify for NPNS or cash flow hedge treatment, or for which NPNS or cash flow hedge treatment is not elected, are recorded at fair value through earnings.

A similar process is also followed by the treasury department as it relates to interest rate derivatives. Examples of accounting guidelines provided to the treasury department staff include, but are not limited to:

- Transactions to lock in an interest rate prior to a debt issuance can be designated as cash flow hedges; to the extent the forecasted debt issuances remain probable of occurring.

- Derivative transactions that do not qualify for cash flow or net investment hedge treatment are marked to fair value through earnings.

- Derivative transactions may be marked to fair value through regulatory assets/liabilities if approved by the appropriate regulatory body. These transactions generally include the effect of interest rate swaps that are included in customer rates.

Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing activities on the Statements of Cash Flows, depending on the classification of the hedged items.

LG&E has elected not to offset net derivative positions against the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

See Notes 13 and 14 for additional information on derivatives.

Revenue

Revenue Recognition

Operating revenues, except for certain energy and energy-related contracts that meet the definition of derivative instruments and "Energy-related businesses," are recorded based on energy deliveries through the end of the calendar month. Unbilled retail revenues result because customers' meters are read and bills are rendered throughout the month, rather than all being read at the end of the month. Unbilled revenues for a month are calculated by multiplying an estimate of unbilled kWh by the estimated average cents per kWh. Unbilled wholesale energy revenues are recorded at month-end to reflect estimated amounts until actual dollars and MWhs are confirmed and invoiced. 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 adjusted for an allowance for doubtful accounts. Accounts receivable that are acquired are initially recorded at fair value on the date of acquisition.

Allowance for Doubtful Accounts

Accounts receivable collectability is evaluated using a combination of factors, including past due status based on contractual terms, trends in write-offs, the age of the receivable, counterparty creditworthiness and economic conditions. Specific events, such as bankruptcies, are also considered. Adjustments to the allowance for doubtful accounts are made when necessary based on the results of analysis, the aging of receivables and historical and industry trends.

Accounts receivable are written off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable previously written off are recorded when it is known they will be received.

The changes in the allowance for doubtful accounts at December 31 were:

		Additions			
	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
2013	$ 1	$ 2	$ 1	$ 2	$ 2
2012	2	2	-	3	1

(a) Primarily related to capital projects, thus the provision was recorded as an adjustment to construction work

in progress.
(b) 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.

Restricted Cash and Cash Equivalents

Bank deposits and other cash equivalents that are restricted by agreement or that have been clearly designated for a specific purpose are classified as restricted cash and cash equivalents. The change in restricted cash and cash equivalents is reported as an investing activity on the Statements of Cash Flows. On the Balance Sheets, the current portion of restricted cash and cash equivalents is shown in "Other current assets" while the noncurrent portion is included in "Other noncurrent assets".

LG&E had restricted cash and cash equivalents for cash collateral posted to counterparties of $22 million and $32 million at December 31, 2013 and 2012.

Fair Value Measurements

LG&E values certain financial and nonfinancial assets and liabilities at fair value. Generally, the most significant fair value measurements relate to price risk management assets and liabilities and cash and cash equivalents. LG&E uses, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques and option-pricing models) and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

LG&E classifies fair value measurements within one of three levels in the fair value hierarchy. The level assigned to a fair value measurement is based on the lowest level input that is significant to the fair value measurement in its entirety. The three levels of the fair value hierarchy are as follows:

- **Level 1 -** quoted prices (unadjusted) in active markets for identical assets or liabilities that are accessible at the measurement date. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

- **Level 2 -** inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for substantially the full term of the asset or liability.

- **Level 3 -** unobservable inputs that management believes are predicated on the assumptions market participants would use to measure the asset or liability at fair value.

Assessing the significance of a particular input requires judgment that considers factors specific to the asset or liability. As such, LG&E's assessment of the significance of a particular input may affect how the assets and liabilities are classified within the fair value hierarchy.

Investments

Generally, the original maturity date of an investment and management's intent and ability to sell an investment prior to its original maturity determine the classification of investments as either short-term or long-term. Investments that would otherwise be classified as short-term, but are restricted as to withdrawal or use for other than current operations or are clearly designated for expenditure in the acquisition or construction of noncurrent assets or for the liquidation of long-term debts, are classified as long-term.

Short-term Investments

Short-term investments generally include certain deposits as well as securities that are considered highly liquid or provide for periodic reset of interest rates. Investments with original maturities greater than three months and less than a year, as well as investments with original maturities of greater than a year that management has the ability and intent to sell within a year, are included in "Other current assets" on the Balance Sheets.

Cost Method Investment

LG&E has an investment in OVEC, which is accounted for using the cost method. The investment is recorded in "Other noncurrent assets" on the Balance Sheets. LG&E and 11 other electric utilities are equity owners of OVEC. OVEC's power is currently supplied to LG&E and 12 other companies affiliated with the various owners. LG&E owns 5.63% of OVEC's common stock. Pursuant to a power purchase agreement, LG&E is contractually entitled to its ownership percentage of OVEC's output, which is approximately 120 MW.

LG&E's investment in OVEC is not significant. The direct exposure to loss as a result of LG&E's involvement with OVEC is generally limited to the value of its investment; however, LG&E may be conditionally responsible for a pro-rata share of certain OVEC obligations. As part of PPL's acquisition of LKE, the value of the power purchase contract was recorded as an intangible asset with an offsetting regulatory liability, both of which are being amortized using the units-of-production method until March 2026, the expiration date of the agreement. See Notes 10 and 15 for additional discussion on the power purchase agreement.

Long-Lived and Intangible Assets

Property, Plant and Equipment

PP&E is recorded at original cost, unless impaired. PP&E acquired in business combinations is recorded at fair value at the time of acquisition, which establishes its original cost. 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 replacements are charged to expense as incurred. LG&E records costs associated with planned major maintenance projects in the period in which the costs are incurred. No costs associated with planned major maintenance projects are accrued in advance of the period in which the work is performed. LG&E accrues costs of removal net of estimated salvage value through depreciation, which is included in the calculation of customer rates over the assets' depreciable lives in accordance with regulatory practices. Cost of removal amounts accrued through depreciation rates are accumulated as a regulatory liability until the removal costs are incurred. See "Asset Retirement Obligations" below and Note 4 for additional information.

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. LG&E’s weighted-average rates of depreciation for regulated utility plant were 4.52% and 4.91% at December 31, 2013 and 2012.

The KPSC approved new lower depreciation rates for LG&E as part of the rate-case settlement agreement reached in November 2012. The new rates became effective January 1, 2013 and resulted in lower depreciation of approximately $8 million in 2013, exclusive of net additions to PP&E.

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, LG&E considers the expected use of the asset; the expected useful life of other assets to which the useful life of the intangible asset may relate; legal, regulatory, or contractual provisions that may limit the useful life; the company's historical experience as evidence of its ability to support renewal or extension; the effects of obsolescence, demand, competition, and other economic factors; and the level of maintenance expenditures required to obtain the expected future cash flows from the asset.

LG&E accounts for emission allowances as intangible assets. LG&E is allocated emission allowances by states based on its generation facilities' historical emissions experience, and have purchased emission allowances generally when it is expected that additional allowances will be needed. The carrying value of allocated emission allowances is initially recorded at zero value and purchased allowances are initially recorded based on their purchase price. When consumed or sold, emission allowances are removed from the Balance Sheets at their weighted-average carrying value. Since the economic benefits of emission allowances are not diminished until they are consumed, emission allowances are not amortized; rather, they are expensed when consumed or a gain or loss is recognized when sold. Such expense is included in "Fuel" on the Statements of Income. Gains and losses on the sale of emission allowances are included in "Other operation and maintenance" on the Statements of Income.

Asset Impairment (Excluding Investments)

LG&E reviews long-lived assets that are subject to depreciation or amortization, including finite-lived intangibles, for impairment when events or circumstances indicate carrying amounts may not be recoverable. A long-lived asset classified as held and used is impaired when the carrying amount of the asset exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If impaired, the asset's carrying value is written down to its fair value.

A long-lived asset classified as held for sale is impaired when the carrying amount of the asset (disposal group) exceeds its fair value less cost to sell. If impaired, the asset's (disposal group's) carrying value is written down to its fair value less cost to sell.

Goodwill is reviewed for impairment at the reporting unit level annually or more frequently when events or circumstances indicate that the carrying amount of a reporting unit may be greater than the unit's fair value. Additionally, goodwill must be tested for impairment in circumstances when a portion of goodwill has been allocated to a business to be disposed. LG&E is a single reporting unit.

LG&E 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.

LG&E elected to perform the qualitative step zero evaluation of goodwill in the fourth quarter of 2013 and determined that it was not more likely than not that the fair value of its goodwill was less than its carrying value.

Asset Retirement Obligations

LG&E records liabilities to reflect various legal obligations associated with the retirement of long-lived assets. Initially, this obligation is measured at fair value and offset with an increase in the value of the capitalized asset, which is depreciated over the asset's useful life. Until the obligation is settled, the liability is increased through the recognition of accretion expense classified within "Other operation and maintenance" on the Statements of Income to reflect changes in the obligation due to the passage of time. The accretion and depreciation expenses recorded by LG&E are recorded as a regulatory asset, such that there is no earnings impact.

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 16 for additional information on AROs.

Compensation and Benefits

Defined Benefits

LG&E sponsors and participates in defined benefit pension and other postretirement plans. The plans LG&E participates in are sponsored by LKE. LKE allocates a portion of the liability and net periodic defined benefit pension and other postretirement costs of certain plans to LG&E based on its participation. 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.

LG&E and LKE use an accelerated amortization method for the recognition of gains and losses for its defined benefit pension plans. Under the accelerated method, actuarial gains and losses in excess of 30% of the plan's projected benefit obligation are amortized on a straight-line basis over one-half of the expected average remaining service of active plan participants. Actuarial gains and losses in excess of 10% of the greater of the plan's projected benefit obligation or the market-related value of plan assets and less than 30% of the plan's projected benefit obligation are amortized on a straight-line basis over the expected average remaining service period of active plan participants.

See Note 8 for a discussion of defined benefits.

Taxes

Income Taxes

LG&E is included in PPL's consolidated U.S. federal income tax return.

Significant management judgment is required in developing LG&E's provision for income taxes, primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and 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. LG&E uses a two-step process to evaluate tax positions. The first step requires LG&E 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 LG&E to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact the financial statements of LG&E in 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.

LG&E records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. LG&E considers the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies in initially recording and subsequently reevaluating the need for valuation allowances. If LG&E determines that it is able to realize deferred tax assets in the future in excess of recorded net deferred tax assets, adjustments to the valuation allowances increase income by reducing tax expense in the period that such determination is made. Likewise, if LG&E determines that it is not able to realize all or part of net deferred tax assets in the future, adjustments to the valuation allowances would decrease income by increasing tax expense in the period that such determination is made.

LG&E defers investment tax credits when the credits are utilized and amortizes the deferred amounts over the average lives of the related assets.

LG&E recognizes interest and penalties in "Income Taxes" on its Statements of Income.

See Note 3 for additional discussion regarding income taxes.

The provision for LG&E's deferred income taxes for regulated assets is based upon the ratemaking principles reflected in rates established by the 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."

The income tax provision for LG&E is calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if LG&E filed a separate return. Tax benefits are not shared between companies. A tax benefit inures only to the entity that gave rise to said benefit. The effect of PPL filing a consolidated tax return is taken into account in the settlement of current taxes and the recognition of deferred taxes. LG&E's intercompany tax receivables (payables) were $(8) million and $5 million at December 31, 2013 and 2012.

Taxes, Other Than Income

LG&E presents sales taxes in "Other current liabilities" on the Balance Sheets. These taxes are not separately 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

LG&E evaluates whether arrangements entered into contain leases for accounting purposes. See Note 7 for a discussion of arrangements under which LG&E is a lessee for accounting purposes.

Fuel, Materials and Supplies

Fuel, natural gas stored underground and materials and supplies are valued at the lower of cost or market using the average cost method. Fuel costs for electric generation are charged to expense as used. For LG&E, natural gas supply costs are charged to expense as delivered to the distribution system. See Note 4 for further discussion of the fuel adjustment clause and gas supply clause.

"Fuel, materials and supplies" on the Balance Sheets consisted of the following at December 31.

	2013	2012
Fuel	$ 64	$ 61
Natural gas stored underground (a)	48	42
Materials and supplies	42	39
Total	$ 154	$ 142

(a) The majority of LG&E's natural gas stored underground is held to serve retail customers

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.

New Accounting Guidance Adopted

Improving Disclosures about Offsetting Balance Sheet Items

Effective January 1, 2013, LG&E retrospectively adopted accounting guidance issued to enhance disclosures about derivative instruments that either (1) offset on the balance sheet or (2) are subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet.

The adoption of this guidance resulted in enhanced disclosures but did not have a significant impact on LG&E. See Note 14 for the new disclosures.

Testing Indefinite-Lived Intangible Assets for Impairment

Effective January 1, 2013, LG&E prospectively adopted accounting guidance that allows an entity to elect the option to first make a qualitative evaluation about the likelihood of an impairment of an indefinite-lived intangible asset. If, based on this assessment, the entity determines that it is more likely than not that the fair value of the indefinite-lived intangible asset exceeds the carrying amount, a quantitative impairment test does not need to be performed. If the entity concludes otherwise, a quantitative impairment test must be performed by determining the fair value of the asset and comparing it with the carrying value. The entity would record an impairment charge, if necessary.

The adoption of this guidance did not have a significant impact on LG&E.

2. Preferred Securities

LG&E is authorized to issue up to 1,720,000 shares of preferred stock at a $25 par value and 6,750,000 shares of preferred stock without par value. LG&E had no preferred stock issued or outstanding in 2013 or 2012.

3. Income and Other Taxes

The provision for LG&E's deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the KPSC and the FERC. The difference in the provision for deferred income taxes for regulated assets and 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.

Significant components of LG&E's deferred income tax assets and liabilities were as follows at December 31.

	2013	2012
Deferred Tax Assets		
Regulatory liabilities	$ 59	$ 54
Deferred investment tax credits	15	16
Income taxes due to customers	19	21
Other	28	9
Total deferred tax assets	121	100
Deferred Tax Liabilities		
Plant - net	585	526
Regulatory assets	83	86
Accrued pension costs	24	27
Other	8	9
Total deferred tax liabilities	700	648
Net deferred tax liability	$ 579	$ 548

LG&E expects to have adequate levels of taxable income to realize its recorded deferred income tax assets.

At December 31, 2013, LG&E had $10 million of federal net operating loss carryforwards that expire in 2032 and $22 million of state net operating loss carryforwards that expire in 2030.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Details of the components of income tax expense, a reconciliation of federal income taxes derived from statutory tax rates applied to "Income Before Income Taxes" to income taxes for reporting purposes, and details of "Taxes, other than income" at December 31 were:

	2013	2012
Income Tax Expense (Benefit)		
Current - Federal	$ 52	$ (2)
Current - State	16	3
Total Current Expense (Benefit)	68	1
Deferred - Federal	33	65
Deferred - State	(2)	6
Total Deferred Expense, excluding benefits of operating loss carryforwards	31	71
Investment tax credit, net - Federal	(2)	(3)
Tax benefit of operating loss carryforwards		
Deferred - Federal	(3)	-
Total Tax Benefit of Operating Loss Carryforwards	(3)	-
Total income tax expense	$ 94	$ 69
Total income tax expense - Federal	$ 80	$ 60
Total income tax expense - State	14	9
Total income tax expense	$ 94	$ 69

	2013	2012
Reconciliation of Income Taxes		
Federal income tax on Income Before Income Taxes at statutory tax rate - 35%	$ 90	$ 67
Increase (decrease) due to:		
State income taxes, net of federal income tax benefit	10	5
Amortization of investment tax credit	(2)	(3)
Other	(4)	-
Total increase	4	2
Total income tax expense	$ 94	$ 69
Effective income tax rate	36.6%	35.9%

	2013	2012
Taxes, other than income		
Property and other	$ 24	$ 23
Total	$ 24	$ 23

Unrecognized Tax Benefits

LG&E's unrecognized tax benefits and changes in those unrecognized tax benefits are insignificant at December 31, 2013 and 2012. At December 31, 2013, no significant changes in unrecognized tax benefits are projected over the next 12 months.

At December 31, the total unrecognized tax benefits and related indirect effects that, if recognized, would decrease the effective tax rate were insignificant.

At December 31, 2013 and 2012, receivable (payable) balances were recorded for interest related to tax positions. The amounts were insignificant. The interest expense (benefit) was recognized in income taxes. The amounts were insignificant.

The income tax provisions for LG&E are calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if each subsidiary filed a separate consolidated return. Based on this tax sharing agreement, LG&E indirectly files tax returns in two major tax jurisdictions. With few exceptions, at December 31, 2013, these jurisdictions, as well as the tax years that are no longer subject to examination, were as follows:

U.S. (federal) (a)	10/31/2010 and prior
Kentucky (state)	2010 and prior

(a) The ten month period ending October 31, 2010 remains open under the standard three year statute of limitations; however, the IRS has completed its audit of these periods under the Compliance Assurance Process, effectively closing them to audit adjustments. No issues remain outstanding.

4. Utility Rate Regulation

Regulatory Assets and Liabilities

As discussed in Note 1 and summarized below, LG&E reflects the effects of regulatory actions in the financial statements for its cost-based rate-regulated utility operations. Regulatory assets and liabilities are classified as current if, upon initial recognition, the entire amount related to that item will be recovered or refunded within a year of the balance sheet date.

LG&E is subject to the jurisdiction of the KPSC and FERC.

LG&E'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, LG&E 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. LG&E recovers in customer rates the cost of coal contracts, power purchases and emission allowances. As a result, management believes the regulatory assets and liabilities created to offset the fair value amounts at LKE’s acquisition date meet the recognition criteria established by existing accounting guidance and eliminate any rate-making impact of the fair value adjustments. LG&E's customer rates will continue to reflect the original contracted prices for these contracts.

The following tables provide information about the regulatory assets and liabilities of cost-based rate-regulated utility operations at December 31.

	2013	2012
Current Regulatory Assets:		
Environmental cost recovery	$ 2	$ 1
Gas supply clause	10	11
Fuel adjustment clause	2	6
Demand side management	3	1
Total current regulatory assets	$ 17	$ 19
Noncurrent Regulatory Assets:		
Defined benefit plans	$ 164	$ 232
Storm costs	51	59
Unamortized loss on debt	18	20
Interest rate swaps	44	67
AROs	21	15
Other	5	7
Total noncurrent regulatory assets	$ 303	$ 400
Current Regulatory Liabilities:		
Gas supply clause	$ 3	$ 4
Gas line tracker	6	-
Total current regulatory liabilities	$ 9	$ 4
Noncurrent Regulatory Liabilities:		
Coal contracts (a)	$ 43	$ 61
Power purchase agreement - OVEC (a)	69	75
Net deferred tax assets	26	28
Interest rate swaps	43	7
Other	2	3
Total noncurrent regulatory liabilities	$ 183	$ 174

(a) These liabilities were recorded as offsets to certain intangible assets that were recorded at fair value upon the acquisition of LKE.

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 the portion of unrecognized transition obligation, prior service cost and net actuarial losses that will be recovered in defined benefit plans expense through future base rates based upon established regulatory practices 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 re-measured. Of the regulatory asset and liability balances recorded, costs of $13 million are expected to be amortized into net periodic defined benefit costs in 2014.

Storm Costs

LG&E has the ability to request from the KPSC the authority to treat expenses related to specific extraordinary storms as a regulatory asset and defer and amortize such costs for regulatory accounting and reporting purposes. Once such authority is granted, LG&E can request recovery of those expenses in a base rate case.

Unamortized Loss on Debt

Unamortized loss on reacquired debt represents losses on long-term debt reacquired or redeemed that have been deferred and will be amortized and recovered over either the original life of the extinguished debt or the life of the replacement debt (in the case of refinancing). Such costs are being amortized through 2035.

Environmental Cost Recovery

Kentucky law permits LG&E to recover the costs, including a return of operating expenses and a return of and on capital invested, of complying with the Clean Air Act and those federal, state or local environmental requirements which apply to coal combustion wastes and by-products from coal-fired electric generating facilities. The KPSC requires reviews of the past operations of the environmental surcharge for six-month and two-year billing periods to evaluate the related charges, credits and rates of return, as well as to provide for the roll-in of ECR amounts to base rates each two-year period. The ECR regulatory asset or liability represents the amount that has been under- or over-recovered due to timing or adjustments to the mechanism and is typically recovered within 12 months. As a result of the settlement agreement in the 2012 rate case, beginning in 2013, LG&E will receive a 10.25% return on equity for all ECR projects included in the 2009 and 2011 compliance plans. In 2012, LG&E was authorized to receive a 10.63% return on equity for projects associated with the 2009 compliance plan and a 10.10% return on equity for projects associated with the 2011 compliance plan.

Gas Supply Clause

LG&E's natural gas rates contain a gas supply clause, whereby the expected cost of natural gas supply and variances between actual and expected costs from prior periods are adjusted quarterly in LG&E's rates, subject to approval by the KPSC. The gas supply clause includes a separate natural gas procurement incentive mechanism, which allows LG&E's rates to be adjusted annually to share variances between actual costs and market indices between the shareholders and the customers during each performance-based rate year (12 months ending October 31). The regulatory assets or liabilities represent the total amounts that have been under- or over-recovered due to timing or adjustments to the mechanisms and are typically recovered within 18 months.

Fuel Adjustment Clauses

LG&E'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 LG&E's rates. The KPSC requires public hearings at six-month intervals to examine past fuel adjustments and at two-year intervals to review past operations of the fuel 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.

Demand Side Management

LG&E's DSM programs consist of energy efficiency programs which are intended to reduce peak demand and delay the investment in additional power plant construction, provide customers with tools and information to become better managers of their energy usage and prepare for potential future legislation governing energy efficiency. LG&E's rates contain a DSM provision which includes a rate recovery mechanism that provides for concurrent recovery of DSM costs, and allows for the recovery of DSM revenues from lost sales associated with the DSM programs. Additionally, LG&E earns an approved return on equity for capital expenditures associated with the residential and commercial load management/demand conservation programs. The cost of DSM programs is assigned only to the class or classes of customers that benefit from the programs.

Interest Rate Swaps

In November 2012 and April 2013, LG&E entered into forward-starting interest rate swaps with PPL that hedged the interest payments on new debt that was expected to be issued in 2013. In September 2013, these hedges were terminated and LG&E entered into new forward-starting interest rate swaps with PPL, effectively extending the start date of the prior hedges from September 2013 to December 2013. All of these swaps had terms identical to forward-starting swaps entered into by PPL with third parties. New debt totaling $250 million was issued in November 2013 and the hedges issued in September were terminated in November 2013. Net cash settlements of $43 million were received on the swaps that were terminated in September and November, which are included in "Cash Flows from Operating Activities" on the Statements of Cash Flows. Net realized gains on these swaps will be returned through regulated rates. As such, the net settlements were reclassified from AOCI to regulatory liabilities and are being recognized in "Interest Expense" on the Statements of Income over the life of the newly issued debt. For the year ended December 31, 2013, there was no hedge ineffectiveness recorded for the interest rate derivatives. See Note 14 for additional information related to the forward-starting interest rate swaps.

In addition to the hedges terminated as a result of the debt issuance, realized amounts associated with LG&E's interest rate swaps, including a terminated swap contract from 2008, are recoverable through rates based on an order from the KPSC, LG&E's unrealized losses and gains are recorded as a regulatory asset or liability until they are realized as interest expense. Interest expense from existing swaps is realized and recovered over the terms of the associated debt, which matures through 2033. Amortization of the gain or loss related to the 2008 terminated swap contract is to be recovered through 2035, as approved by the KPSC.

AROs

As discussed in Note 1, the accretion and depreciation expenses related to LG&E's AROs are recorded as a regulatory asset, such that there is no earnings impact. When an asset with an ARO is retired, the related ARO regulatory asset is offset against the associated cost of removal regulatory liability, PP&E and ARO liability.

Gas Line Tracker

In the 2012 rate case order, the KPSC approved the GLT rate recovery mechanism. The GLT authorizes LG&E to recover its incremental operating expenses and depreciation, and to earn a 10.25% return on equity for capital associated with the five year gas service riser and leak mitigation program. As part of this program, LG&E makes necessary repairs and assumes ownership of natural gas lines. LG&E annually files projected costs in October to become effective on the first billing cycle in January. After the completion of a plan year, LG&E submits a balancing adjustment filing to the KPSC to amend rates charged for the differences between the actual costs and actual GLT charges for the preceding year.

Coal Contracts

As a result of purchase accounting associated with PPL's acquisition of LKE, LG&E's coal contracts were recorded at fair value on the Balance Sheets with offsets to regulatory assets for those contracts with unfavorable terms relative to current market prices and offsets to regulatory liabilities for those contracts with favorable terms relative to current market prices. These regulatory assets and liabilities are being amortized over the same terms as the related contracts, which expire at various times through 2016.

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 regulatory liabilities. The regulatory liabilities are being amortized using the units-of-production method until March 2026, the expiration date of the agreement at the date of the acquisition.

Regulatory Liability Associated with Net Deferred Tax Assets

LG&E's regulatory liabilities associated with net deferred tax assets represent the future revenue impact from the reversal of deferred income taxes required primarily for unamortized investment tax credits. These regulatory liabilities are recognized when the offsetting deferred tax assets are recognized. For general-purpose financial reporting, these regulatory liabilities and the deferred tax assets are not offset; rather, each is displayed separately.

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NOTES TO FINANCIAL STATEMENTS (Continued)

Regulatory Matters

Rate Case Proceedings

In December 2012, the KPSC approved a rate case settlement agreement providing for increases in annual base electricity rates of $34 million and an increase in annual base gas rates of $15 million and authorized a 10.25% return on equity. The approved rates became effective January 1, 2013.

CPCN Filings

In January 2014, LG&E and KU filed an application for a CPCN with the KPSC requesting approval to build a NGCC generating unit at KU's Green River generating site and a solar generating facility at the E. W. Brown generating site.

Storm Costs

In August 2011, a strong storm hit LG&E's service area causing significant damage and widespread outages for approximately 139,000 customers. LG&E filed an application with the KPSC in September 2011, requesting approval of a regulatory asset recorded to defer, for future recovery, $8 million in incremental operation and maintenance expenses related to the storm restoration. An order was received in December 2011 granting the request. On December 20, 2012, the KPSC, in the approval of the unanimous rate case settlement agreement, authorized regulatory asset recovery effective January 1, 2013, over a five year period.

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NOTES TO FINANCIAL STATEMENTS (Continued)

5. Financing Activities

Credit Arrangements and Short-term Debt

LG&E maintains a credit facility to enhance liquidity, provide credit support and provide a backup to its commercial paper program. The amounts borrowed below are recorded as “Short-term debt” on the Balance Sheets. The following credit facility was in place at:

	December 31, 2013				
	Expiration Date	Capacity	Borrowed	Letters of Credit Issued and Commercial Paper Backup	Unused Capacity
Syndicated Credit Facility (a) (b)	Nov. 2017	$ 500	-	$ 20	$ 480

	December 31, 2012	
	Borrowed	Letters of Credit Issued and Commercial Paper Backup
Syndicated Credit Facility (a) (b)	-	$ 55

(a) LG&E pays customary fees under its facility and borrowings generally bear interest at LIBOR-based rates plus an applicable margin.

(b) The facility contains a financial covenant requiring debt to total capitalization not to exceed 70% as calculated in accordance with the facility and other customary covenants.

LG&E 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 LG&E's Syndicated Credit Facility. The following commercial paper program was in place at:

December 31, 2013			
Weighted - Average Interest Rate	**Capacity**	**Commercial Paper Issuances**	**Unused Capacity**
0.29%	$ 350	$ 20	$ 330

December 31, 2012	
Weighted - Average Interest Rate	**Commercial Paper Issuances**
0.42%	$ 55

See Note 11 for discussion of intercompany borrowings.

Long-term Debt

	Weighted-Average Rate	Maturities	December 31, 2013
Senior Secured Notes/First Mortgage Bonds (a) (b)	2.77%	2015 - 2043	$ 1,359
Fair market value adjustments			(1)
Unamortized discount			(5)
Total Long-term Debt			$ 1,353

			December 31, 2012
Senior Secured Notes/First Mortgage Bonds (a) (b)	2.49%	2015 - 2040	$ 1,109
Fair market value adjustments			6
Unamortized discount			(3)
Total Long-term Debt			$ 1,112

(a) LG&E's first mortgage bonds are secured by the lien of the LG&E 2010 Mortgage Indenture which creates a lien, subject to certain exceptions and exclusions, on substantially all of LG&E's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity and the storage and distribution of natural gas. The aggregate carrying value of the property subject to the lien was $3.2 billion and $2.7 billion at December 31, 2013 and 2012.

(b) Includes LG&E's series of first mortgage bonds that were issued to the respective trustees of tax-exempt revenue bonds to secure its respective obligations to make payments with respect to each series of bonds. The first mortgage bonds were issued in the same principal amount, contain payment and redemption provisions that correspond to and bear the same interest rate as such tax-exempt revenue bonds. These first mortgage bonds were issued under the LG&E 2010 Mortgage Indenture and are secured as noted in (a) above. The related tax-exempt revenue bonds were issued by various governmental entities, principally counties in Kentucky, on behalf of LG&E. The related revenue bond documents allow LG&E to convert the interest rate mode on the bonds from time to time to a commercial paper rate, daily rate, weekly rate, term rate of at least one year or, in some cases, an auction rate or a LIBOR index rate.

At December 31, 2013, the aggregate tax-exempt revenue bonds issued on behalf of LG&E that were in a term rate mode totaled $294 million. At December 31, 2013, the aggregate tax-exempt revenue bonds issued on behalf of LG&E that were in a variable rate mode totaled $280 million.

Several series of the tax-exempt revenue bonds are insured by monoline bond insurers whose ratings were reduced due to exposures relating to insurance of sub-prime mortgages. Of the bonds outstanding, $135 million are in the form of insured auction rate securities, wherein interest rates are reset either weekly or every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. During 2008, interest rates increased, and LG&E experienced failed auctions when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture. As noted above, the instruments governing these auction rate bonds permit LG&E to convert the bonds to other interest rate modes.

Certain variable rate tax-exempt revenue bonds totaling $120 million at December 31, 2013, are subject to tender for purchase by LG&E at the option of the holder and to mandatory tender for purchase by LG&E upon the occurrence of certain events.

None of the outstanding debt securities noted above have sinking fund requirements. The aggregate maturities of long-term debt for the periods 2014 through 2018 and thereafter are $250 million in 2015 and $1,109 million after 2018.

Long-term Debt and Equity Securities Activities

In November 2013, LG&E issued $250 million of 4.65% First Mortgage Bonds due 2043. LG&E received proceeds of $246 million, net of discounts and underwriting fees, which were used for repayment of short-term debt, including commercial paper, for capital expenditures and for other general corporate purposes.

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.

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 their 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 these subsidiaries may not satisfy their debts from the assets of LKE (or their 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, Capital Contributions and Related Restrictions

LG&E is subject to Section 305(a) of the Federal Power Act, which makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in capital account." The meaning of this limitation has never been clarified under the Federal Power Act. LG&E believes, however, that this statutory restriction, as applied to its circumstances, would not be construed or applied by the FERC to prohibit the payment from retained earnings of dividends that are not excessive and are for lawful and legitimate business purposes. In February 2012, LG&E 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, FERC approved the petition with the further condition that LG&E may not pay dividends if such payment would cause its adjusted equity ratio to fall below 30% of total capitalization. Accordingly, at December 31, 2013, net assets of $1.0 billion were restricted for purposes of paying dividends to LKE, and net assets of $1.0 billion were available for payment of dividends to LKE. LG&E believes it will not be required to change its current dividend practices as a result of the foregoing requirement. Orders from the KPSC require LG&E to obtain prior consent or approval before lending amounts to PPL.

During the year, LG&E paid dividends of $99 million to its parent, LKE, and received capital contributions of $86 million from LKE.

6. Acquisitions, Development and Divestitures

LG&E from time to time 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 the projects, sell, cancel or expand them, execute tolling agreements or pursue other options. Any resulting transactions may impact future financial results.

Development

Cane Run Unit 7 Construction

In September 2011, LG&E and KU filed an application for a CPCN with the KPSC requesting approval to build Cane Run Unit 7. In May 2012, the KPSC issued an order approving the request. LG&E will own a 22% undivided interest, and KU will own a 78% undivided interest in the new NGCC generating unit. A formal request for recovery of the costs associated with the construction was not included in the CPCN application but certain Cane Run Unit 7 construction work in progress has been included in base rates and the remaining capital costs are expected to be included in future rate proceedings. LG&E and KU commenced preliminary construction activities in the third quarter of 2012 and project construction is expected to be completed by May 2015. The project, which includes building a natural gas supply pipeline and related transmission projects, has an estimated cost of approximately $600 million.

In conjunction with this construction and to meet new, more stringent EPA regulations with a 2015 compliance date, LG&E anticipates retiring three older coal-fired electric generating units at the Cane Run plant, which have a combined summer capacity rating of 563 MW.

Future Capacity Needs

In January 2014, LG&E and KU filed an application for a CPCN with the KPSC requesting approval to construct a NGCC unit at KU's Green River generating site (Green River Unit 5) and a solar generating facility at the E. W. Brown generating site. Subject to finalizing details, regulatory applications, permitting and construction schedules, Green River Unit 5 is expected to have approximately 700 MW of capacity at an estimated cost of $700 million and is planned to be operational in 2018. Green River Unit 5 will be jointly owned by LG&E and KU, with LG&E owning a 40% undivided interest and KU owning a 60% undivided interest. The solar generating facility is expected to have approximately 10 MW of capacity at an estimated cost of $36 million and is planned to be operational in 2016. The solar generating facility will be jointly owned by LG&E and KU, with LG&E owning a 36% undivided interest and KU owning a 64% undivided interest.

7. Leases

LG&E has entered into various agreements for the lease of office space, vehicles, land, gas storage and other equipment.

Rent expense for operating leases was $7 million at December 31, 2013 and 2012.

Total future minimum rental payments for all operating leases are estimated to be:

2014	$	6
2015		5
2016		4
2017		2
2018		2
Thereafter		12
Total	$	31

8. Retirement and Postemployment Benefits

Defined Benefits

LG&E sponsors and participates in non-contributory defined benefit pension plans. These plans are applicable to the majority of LG&E employees. The plan LG&E participates in is sponsored by LKE. LG&E 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 is reasonable. LG&E’s and LKE’s defined benefit pension plans were closed to new salaried and bargaining unit employees hired after December 31, 2005. Employees hired after December 31, 2005 receive additional company contributions above the standard matching contributions to their savings plans. The 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 following table provides the components of net periodic defined benefit costs for LG&E's pension benefit plan for the years ended December 31.

	LG&E Sponsored Pension Benefits	
	2013	2012
Net periodic defined benefit costs (credits):		
Service cost	$ 2	$ 2
Interest cost	14	14
Expected return on plan assets	(20)	(19)
Amortization of:		
Prior service cost (credit)	2	3
Actuarial (gain) loss	14	11
Net periodic defined benefit costs (credits)	$ 12	$ 11
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets - Gross:		
Net (gain) loss	$ (20)	$ 18
Amortization of:		
Prior service cost	(2)	(2)
Actuarial (loss)	(14)	(11)
Total recognized in regulatory assets	(36)	5
Total recognized in net periodic benefit costs and regulatory assets	$ (24)	$ 16

For the plan sponsored by LG&E, the estimated amounts to be amortized from regulatory assets into net periodic defined benefit costs in 2014 are $8 million ($2 million amortization of prior service cost and $6 million amortization of actuarial loss). For the plan LG&E participates in, estimated amounts to be amortized from regulatory assets into net periodic defined benefit costs in 2014 are $5 million ($2 million amortization of prior service cost and $3 million amortization of actuarial loss).

The net periodic defined benefit costs charged to operating expense, excluding amounts charged to construction and other non-expense accounts, for LG&E’s pension benefits were $14 million and $13 million in 2013 and 2012. Allocations to LG&E for net periodic defined benefit costs charged to operating expense, excluding amounts charged to construction and other non-expense accounts, for pension benefits were $5 million in 2013 and 2012. Net periodic defined benefits costs charged to operating expense, excluding amounts charged to construction and other non-expense accounts for other postretirement benefits were $4 million and $5 million in 2013 and 2012. These allocated amounts are based on LG&E’s participation in those plans, which management believes is reasonable.

The following weighted-average assumptions were used in the valuation of the benefit obligations at December 31.

	LG&E Sponsored Pension Benefits	
	2013	**2012**
Discount rate	5.13%	4.20%

The following weighted-average assumptions were used to determine the net periodic defined benefit costs for the years ended December 31.

	LG&E Sponsored Pension Benefits	
	2013	**2012**
Discount rate	4.20%	5.00%
Expected return on plan assets (a)	7.10%	7.25%

(a) The expected long-term rates of return for pension benefits are based on management's projections using a best-estimate of expected returns, volatilities and correlations for each asset class. Each plan's specific current and expected asset allocations are also considered in developing a reasonable return assumption.

The funded status of LG&E's plan at December 31, was as follows:

	LG&E Sponsored Pension Benefits	
	2013	**2012**
Change in Benefit Obligation		
Benefit Obligation, beginning of period	$ 331	$ 298
Service cost	2	1
Interest cost	14	14
Actuarial (gain) loss	(35)	32
Gross benefits paid (a)	(21)	(14)
Benefit Obligation, end of period	$ 291	$ 331
Change in Plan Assets		
Plan assets at fair value, beginning of period	287	256
Actual return on plan assets	4	32
Employer contributions	11	13
Gross benefits paid (a)	(21)	(14)
Plan assets at fair value, end of period	281	287
Funded Status, end of period	$ (10)	$ (44)
Amounts recognized in the Balance Sheets consist of:		
Noncurrent liability	(10)	(44)
Net amount recognized, end of period	$ (10)	$ (44)

(a) LG&E's pension plan offered a limited-time program in 2013 during which terminated vested participants could elect to receive their accrued pension benefit as a one-time lump-sum payment. The increase in gross benefits paid is primarily the result of $7 million of lump-sum cash payments made to terminated vested participants in 2013 in connection with this offering.

LG&E's pension plan had projected and accumulated benefit obligations in excess of plan assets at December 31, 2013 and 2012.

In addition to the plan it sponsors, LG&E is allocated a portion of the funded status and costs of certain defined benefit plans sponsored by LKE based on its participation in those plans, which management believes are reasonable. The actuarially determined obligations of current active employees and retired employees are used as a basis to allocate total plan activity, including active and retiree costs and obligations. Allocations to LG&E for pension benefits resulted in a liability of $9 million and $58 million at December 31, 2013 and 2012.

Allocations to LG&E for other postretirement benefits resulted in a liability of $73 million and $81 million at December 31, 2013 and 2012.

Plan Assets - Pension Plans

The pension plans sponsored by LKE and LG&E are 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. The investment strategy for the Master Trust is to achieve a risk-adjusted return on a mix of assets that, in combination with the Company’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 on a plan basis based on input from external consultants with a goal of limiting funded status volatility. The EBPB monitors the investments in each portfolio on a plan basis, 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 on a plan basis, as well as the weighted average of such guidelines, as of the end of 2013 are presented below.

The asset allocation for the trust and the target allocation by portfolio, at December 31, are as follows:

	Percentage of Trust Assets	2013 Target Asset Allocation (a)	
	2013 (a)	Weighted Average	LKE Plans
Growth Portfolio	**59%**	**55%**	**55%**
Equity securities	30%		
Debt securities (b)	17%		
Alternative investments	12%		
Immunizing Portfolio	**39%**	**43%**	**43%**
Debt securities (b)	40%		
Derivatives	(1)%		
Liquidity Portfolio	**2%**	**2%**	**2%**
Total	100%	100%	100%

	Percentage of Trust Assets
	2012
Growth Portfolio	**58%**
Equity securities	31%
Debt securities (b)	18%
Alternative investments	9%
Immunizing Portfolio	**41%**
Debt securities (b)	34%
Derivatives	1%
Liquidity Portfolio	**1%**
Total	100%

(a) Allocations exclude consideration of a guaranteed annuity contract held by the LG&E and KU Retirement Plan.
(b) Includes commingled debt funds, which the Company treats as debt securities for asset allocation purposes.

LG&E’s and LKE’s pension plans’ assets are invested solely in the PPL Services Corporation Master Trust, which is fully disclosed below. The fair value of LG&E’s plan's assets of $281 million and $287 million at December 31, 2013 and 2012 represents an interest of approximately 7% in the Master Trust for both years. The fair value of LKE’s plan’s assets of $1.2 billion and $1.1 billion at December 31, 2013 and 2012 represent approximately 29% and 26% in the Master Trust.

The fair value of net assets in the pension plan trusts by asset class and level within the fair value hierarchy was:

	December 31, 2013			
	Total	Level 1	Level 2	Level 3
Cash and cash equivalents	$ 120	$ 120	$ -	$ -
Equity securities				
U.S.:				
Large-cap	480	134	346	-
Small-cap	137	137	-	-
Commingled debt	749	13	736	-
International	630	163	467	-
Debt securities:				
U.S. Treasury and U.S. government sponsored agency	617	563	54	-
Residential/commercial backed securities	12	-	11	1
Corporate	963	-	940	23
Other	24	-	24	-
International	7	-	7	-
Alternative investements				
Commodities	108	-	108	-
Real estate	134	-	134	-
Private equity	80	-	210	80
Hedge funds	210	-	-	-
Derivatives:				
Interest rate swaps and swapations	(49)	-	(49)	-
Other	12	-	12	-
Insurance contracts	37	-	-	37
PPL Services Corporation Master Trust assets, at fair value	$ 4,271	$ 1,130	$ 3,000	$ 141
Receivables and payables, net (a)	-	-	-	-
401(h) account restricted for other postretirement benefit obligations	(115)	-	-	-
Total PPL Services Corporation Master Trust pension assets	$ 4,156			

	December 31, 2012			
	Total	**Level 1**	**Level 2**	**Level 3**
Cash and cash equivalents	$ 84	$ 84	$ -	$ -
Equity securities				
U.S.:				
Large-cap	558	206	352	-
Small-cap	124	124	-	-
Commingled debt	676	56	620	-
International	557	184	373	-
Debt securities:				
U.S. Treasury and U.S. government sponsored agency	704	634	70	-
Residential/commercial backed securities	12	-	11	1
Corporate	874	-	847	27
Other	24	-	23	1
International	7	-	7	-
Alternative investements				
Commodities	59	-	59	-
Real estate	93	-	93	-
Private equity	75	-	-	75
Hedge funds	125	-	125	-
Derivatives:				
Interest rate swaps and swapations	36	-	36	-
Other	2	-	2	-
Insurance contracts	42	-	-	42
PPL Services Corporation Master Trust assets,at fair value	$ 4,052	$ 1,288	$ 2,618	$ 146
Receivables and payables, net (a)	(11)	-	-	-
401(h) account restricted for other postretirement benefit obligations	(102)	-	-	-
Total PPL Services Corporation Master Trust pension assets	$ 3,939			

(a) 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 pension trust assets classified as Level 3 at December 31, 2013 is as follows:

	Residential/ commercial backed securities	**Corporate debt**	**Private equity**	**Insurance contracts**	**Other debt**	**Total**
Balance at beginning of period	$ 1	$ 27	$ 75	$ 42	$ 1	$ 146
Actual return on plan assets	-	-	-	-	-	-
Relating to assets still held at the reporting date	-	-	3	2	-	5
Relating to assets sold the period during	-	5	-	-	-	5
Purchases, sales and settlements	-	(9)	2	(7)	-	(14)
Transfers from level 2 to level 3	-	-	-	-	-	-
Transfers from level 3 to level 2	-	-	-	-	(1)	(1)
Balance at end of period	$ 1	$ 23	$ 80	$ 37	$ -	$ 141

A reconciliation of pension trust assets classified as Level 3 at December 31, 2012 is as follows:

	Residential/ commercial backed securities	**Corporate debt**	**Private equity**	**Insurance contracts**	**Other debt**	**Total**
Balance at beginning of period	$ -	$ 7	$ 45	$ 46	$ -	$ 98
Actual return on plan assets	-	-	-	-	-	-
Relating to assets still held at the reporting date	-	1	10	3	-	14
Relating to assets sold the period during	-	2	-	-	-	2
Purchases, sales and settlements	1	21	20	(7)	-	35
Transfers from level 2 to level 3	-	-	-	-	1	1
Transfers from level 3 to level 2	-	(4)	-	-	-	(4)
Balance at end of period	$ 1	$ 27	$ 75	$ 42	$ 1	$ 146

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. These investments are classified as Level 2, except for exchange-traded funds, which are classified as Level 1 based on quoted prices in active markets. The fair value measurements for Level 2 investments are based on firm quotes of net asset values per share, which are not considered obtained from a quoted price in an active market. 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 evaluated prices 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, reported trades, broker/dealer bid/ask prices, benchmark securities and credit valuation adjustments. When necessary, the fair value of debt securities is measured using the income approach, which incorporates similar observable inputs as well as monthly payment data, future predicted cash flows, collateral performance and new issue data. For the PPL Services Corporation 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; and exchange traded funds.

Investments in commodities represent ownership of units of a commingled fund that is invested as a long-only, unleveraged portfolio of exchange-traded futures and forward contracts in tangible commodities to obtain broad exposure to all principal groups in the global commodity markets, including energies, agriculture and metals (both precious and industrial) using proprietary commodity trading strategies. The fund has daily liquidity with a specified notification period. The fund's fair value is based upon a unit value as calculated by the fund's trustee.

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. Four of the partnerships have limited lives of ten years, while the fifth has a life of 15 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 PPL Services Corporation Master Trust has unfunded commitments of $76 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 three hedge fund of 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 all market conditions. Major investment strategies for the hedge fund of funds include long/short equity, market neutral, distressed debt, and relative value. Generally, shares may be redeemed with 65 to 95 days prior written notice. The funds are subject to short term lockups and have limitations on the amount that may be withdrawn based on a percentage of the total net asset value of the fund, among other restrictions. All withdrawals are subject to the general partner's approval. The fair value for two of the funds has been estimated using the net asset value per share and the third fund's fair value is based on an ownership interest in partners' capital to which a proportionate share of net assets is attributed.

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.

Plan Assets – Other Postretirement Benefit Plans

LKE’s postretirement benefit plan is invested primarily in a 401(h) account, with insignificant amounts invested in money market funds within VEBA trusts for liquidity. LKE’s other postretirement benefit plan was invested primarily in a 401(h) account as disclosed in the PPL Services Corporation Master Trusts.

Expected Cash Flows - Defined Benefit Plans

LG&E's defined benefit plan has the option to utilize available prior year credit balances to meet current and future contribution requirements. LG&E does not plan to contribute to its pension plan in 2014. LG&E contributed $8 million to LKE’s pension plan on behalf of LG&E employees in January 2014.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid by the plans for LG&E retirees.

	LG&E Sponsored Pension Plan	Allocated from LKE Pension Plan
2014	$ 15	$ 11
2015	15	11
2016	15	11
2017	16	12
2018	17	12
2019-2023	99	68

Savings Plans

Substantially all employees of LG&E are eligible to participate in a 401(k) deferred savings plan. Employer contributions to the plan were $7 million and $6 million in 2013 and 2012.

9. Jointly Owned Facilities

At December 31, 2013 and 2012, the Balance Sheets reflect the owned interests in the facilities listed below.

	Ownership Interest	Electric Plant	Accumulated Depreciation	Construction Work in Progress
December 31, 2013				
Generating Plants				
E.W. Brown Units 6-7	38.00%	$ 40	$ 7	$ 1
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00%	46	5	1
Trimble County Unit 1	75.00%	308	42	18
Trimble County Unit 2	14.25%	200	19	14
Trimble County Units 5-6	29.00%	29	3	-
Trimble County Units 7-10	37.00%	69	7	1
Cane Run Unit 7	22.00%	-	-	91
Green River Unit 5	40.00%	-	-	1
December 31, 2012				
Generating Plants				
E.W. Brown Units 6-7	38.00%	$ 40	$ 5	$ -
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00%	46	3	-
Trimble County Unit 1	75.00%	304	33	10
Trimble County Unit 2	14.25%	198	14	13
Trimble County Units 5-6	29.00%	29	2	-
Trimble County Units 7-10	37.00%	68	6	2
Cane Run Unit 7	22.00%	-	-	16

LG&E provides its own funding for its share of each of the above facilities. LG&E 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 Purchases, Energy Sales and Other Commitments

Energy Purchase Commitments

LG&E and KU enter into purchase contracts to supply the coal and natural gas requirements for generation facilities and LG&E's gas supply operations. These contracts include the following commitments:

Contract Type	**Maximum Maturity Date**
Coal	2019
Coal Transportation and Fleeting Services	2024
Natural Gas Storage	2024
Natural Gas Transportation	2024

LG&E 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. Future obligations for power purchases from OVEC are unconditional demand payments, comprised of annual minimum debt service payments, as well as contractually required reimbursement of plant operating, maintenance and other expenses as follows:

2014	$ 18
2015	18
2016	18
2017	19
2018	20
Thereafter	504
	$ 597

In addition, LG&E had total energy purchases under the OVEC power purchase agreement of $18 million and $20 million during 2013 and 2012.

Legal Matters

LG&E is involved in legal proceedings, claims and litigation in the ordinary course of business. LG&E cannot predict the outcome of such matters, or whether such matters may result in material liabilities, unless otherwise noted.

Regulatory Issues

See Note 4 for information on regulatory matters related to utility rate regulation.

Enactment of Financial Reform Legislation

The Dodd-Frank Act became effective in July 2010 and includes provisions that impose derivative transaction reporting requirements and require most over-the-counter derivative transactions to be executed through an exchange and to be centrally cleared. The Dodd-Frank Act also provides that the U.S. Commodity Futures Trading Commission (CFTC) may impose collateral and margin requirements for over-the-counter derivative transactions, as well as capital requirements for certain entity classifications. The CFTC is establishing final rules on major provisions in the Dodd-Frank Act through its rulemaking process. Several final rules providing for the definition of the terms "swap", "swap dealer", and "major swap participant" became effective in October 2012. The entity classification thresholds and requirements set forth in these final rules do not require LG&E to register as either a swap dealer or major swap participant. Consequently, as commercial end users, LG&E is not subject to the heightened regulatory requirements applicable to swap dealers or major swap participants, including Business Conduct Standards, enhanced recordkeeping and reporting, clearing and exchange trading of CFTC-mandated swaps and other complex requirements under other CFTC regulations. The Dodd-Frank Act and its implementing regulations, however, have imposed on LG&E significant additional and costly recordkeeping, reporting and documentation requirements.

LG&E could face significantly higher operating costs or may be required to post additional collateral if it or its counterparties are subject to capital or margin requirements as ultimately adopted in the implementing regulations of the Dodd-Frank Act. Additionally, the burden that the Dodd-Frank Act and implementing regulations impose on all market participants could cause decreased liquidity in the bilateral swap market as financial entities discontinue their proprietary trading operations. Decreased liquidity could increase costs for LG&E to successfully meet hedge targets. LG&E will continue to evaluate the provisions of the Dodd-Frank Act and its implementing regulations, but could incur significant costs related to compliance with the Act and regulations.

FERC Market-Based Rate Authority

In 1998, the FERC authorized LG&E and KU to make wholesale sales of electricity and related products at market-based rates. In that order, the FERC directed LG&E and KU to file an updated market analysis within three years after the order, and every three years thereafter. Since then, periodic market-based rate filings with the FERC have been made by LG&E and KU. In June 2011, FERC approved PPL’s market-based rate update for the Southeast region, including LG&E and KU. Also, in June 2011, the FERC issued an order approving LG&E's and KU’s request for a determination that they no longer be deemed to have market power in the BREC balancing area and removing restrictions on their market-based rate authority in such region. LG&E cannot predict the ultimate outcome of these update filings at this time.

Electricity - Reliability Standards

The NERC is responsible for establishing and enforcing mandatory reliability standards (Reliability Standards) regarding the bulk power system. The FERC oversees this process and independently enforces the Reliability Standards.

The Reliability Standards have the force and effect of law and apply to certain users of the bulk power electricity system, including electric utility companies, generators and marketers. Under the Federal Power Act, the FERC may assess civil penalties of up to $1 million per day, per violation, for certain violations.

LG&E monitors its compliance with the Reliability Standards and continues to self-report potential violations of certain applicable reliability requirements and submit accompanying mitigation plans, as required. The resolution of a number of potential violations is pending. Any Regional Reliability Entity (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 by LG&E, certain other instances of potential non-compliance may be identified from time to time. LG&E cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any, other than the amounts currently recorded.

In October 2012, the FERC initiated its consideration of proposed changes to Reliability Standards to address the impacts of Geomagnetic Disturbances on the reliable operation of the bulk-power system, which might, among other things, lead to a requirement to install equipment that blocks geo-magnetically induced currents on implicated transformers. On May 16, 2013, FERC issued Order No. 779, requiring NERC to submit two types of Reliability Standards for FERC's approval in twelve month intervals. The first type would require certain owners and operators of the nation's electricity infrastructure, such as LG&E, to develop and implement operational procedures to mitigate the effects of Geomagnetic Disturbances on the bulk-power system. This NERC proposed standard was filed by NERC with FERC for approval in January of 2014, with a comment due date of March 24, 2014. The second type is to require owners and operators of the bulk-power system to assess certain Geomagnetic Disturbance events and develop and implement plans to protect the bulk-power system from those events and must be filed by NERC with FERC for approval by January 22, 2015. LG&E may be required to make significant expenditures in new equipment or modifications to its facilities to comply with the new requirements. LG&E is unable to predict the amount of any expenditures that may be required as a result of the adoption of any Reliability Standards for Geomagnetic Disturbances.

Environmental Matters

Due to the environmental issues discussed below or other environmental matters, it may be necessary for LG&E 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 impact of these permits and rules.

LG&E 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 which are 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 for LG&E are subject to rate recovery before the KPSC. LG&E can provide no assurances as to the ultimate outcome of future environmental or rate proceedings before regulatory authorities.

Air

CSAPR (formerly Clean Air Transport Rule) and CAIR

In July 2011, the EPA adopted the CSAPR. The CSAPR replaced the EPA's previous CAIR which was invalidated in July 2008 by the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court). CAIR subsequently was effectively reinstated by the D.C. Circuit Court in December 2008, pending finalization of the CSAPR. Like CAIR, CSAPR targeted sources in the eastern U.S. and would have required reductions in sulfur dioxide and nitrogen oxides in two phases (2012 and 2014).

In December 2011, the D.C. Circuit Court stayed implementation of the CSAPR and left CAIR in effect pending a final decision on the validity of the rule. In August 2012, the D.C. Circuit Court issued a ruling invalidating CSAPR, remanding the rule to the EPA for further action, and leaving CAIR in place during the interim. In June 2013, the U.S. Supreme Court granted the EPA's petition for review of the D.C. Circuit Court's August 2012 decision. Oral arguments before the U.S. Supreme Court were held in December 2013. Prior to a revised transport rule from the EPA, coal-fired generating plants could face tighter emission limitations on nitrogen oxides through state action.

The Kentucky fossil-fueled generating plants can meet the CAIR sulfur dioxide emission requirements by utilizing sulfur dioxide allowances (including banked allowances and optimizing existing controls). To meet standards for nitrogen oxides under the CAIR, LG&E will need to buy allowances and/or make operational changes. LG&E does not currently anticipate that the costs of meeting these reinstated CAIR standards will be significant.

National Ambient Air Quality Standards

LG&E’s fossil-fueled generating plants may face further reductions in emissions as a result of more stringent national ambient air quality standards for ozone, nitrogen oxides, sulfur dioxide and/or fine particulates.

In 2010, the EPA finalized a new one-hour standard 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 part of Jefferson County in Kentucky. Attainment must be achieved by 2018. States are working on designations for other areas.

In December 2012, the EPA issued final rules that strengthen the fine particulate standards. Under the final rules, states and the EPA have until 2015 to identify non-attainment areas, and states have until 2020 to achieve attainment for those areas.

LG&E anticipates that some of the measures required for compliance with the CAIR, or the MATS, or the Regional Haze requirements (as discussed below), such as upgraded or new sulfur dioxide scrubbers at certain plants and the previously announced retirement of coal-fired generating units at the Cane Run plant, will help to achieve compliance with the new one-hour sulfur dioxide standard. If additional reductions were to be required, the financial impact could be significant.

Until particulate matter and sulfur dioxide maintenance and compliance plans are developed by the EPA and state or local agencies, including identification and finalization of attainment designations for particulate matter, LG&E cannot predict the impact of the new standards.

MATS

In May 2011, the EPA published a proposed regulation requiring stringent reductions of mercury and other hazardous air pollutants from power plants. In February 2012, the EPA published the final rule, known as the MATS, with an effective date of April 2012. The rule is being challenged by industry groups and states in the D.C. Circuit Court, where oral arguments were held in December 2013. The rule provides for a three-year compliance deadline with the potential for a one-year extension as provided under the statute. LG&E has received compliance extensions for certain plants. LG&E is considering extension requests for other plants as well.

At the time the MATS rule was proposed, LG&E filed requests with the KPSC for environmental cost recovery based on its expected need to install environmental controls including chemical additive and fabric-filter baghouses to remove air pollutants. Recovery of the cost of certain controls was granted by the KPSC in December 2011. LG&E's anticipated retirement of certain coal-fired electricity generating units located at Cane Run is in response to MATS and other environmental regulations. LG&E is continuing to assess whether any revisions of its approved compliance plans will be necessary.

LG&E is continuing to conduct in-depth reviews of the MATS, including the potential implications to scrubber wastewater discharges. See the discussion of effluent limitations guidelines and standards below.

Regional Haze and Visibility

The EPA's regional haze programs were developed under the Clean Air Act to eliminate man-made visibility degradation by 2064. Under the programs, states are required to take action via state plans to make reasonable progress every decade, including the application of Best Available Retrofit Technology (BART) on power plants commissioned between 1962 and 1977.

The primary power plant emissions affecting visibility are sulfur dioxide, nitrogen oxides and particulates. To date, the focus of regional haze activity has been the western U.S. because the EPA had determined that the regional trading program in the eastern U.S. under CSAPR satisfied BART requirements to reduce sulfur dioxide and nitrogen oxides. However, the D.C. Circuit Court's August 2012 decision to vacate and remand CSAPR and to implement CAIR in its place on an interim basis leaves power plants located in the eastern U.S., including LG&E’s plants, exposed to reductions in sulfur dioxide and nitrogen oxides as required by BART, unless the D.C. Circuit Court's decision, now pending before the U.S. Supreme Court, is overturned.

In addition to this exposure stemming from the remand of CSAPR, LG&E's Mill Creek Units 3 and 4 are required to reduce sulfuric acid mist emissions because they were determined to have a significant regional haze impact. These reductions are in the Kentucky Division of Air Quality's regional haze state implementation plan that was submitted to the EPA. LG&E is currently installing sorbent injection technology to comply with these reductions, the costs of which are not expected to be significant.

New Source Review (NSR)

The EPA has continued its NSR enforcement efforts targeting coal-fired generating plants. The EPA has asserted that modification of these plants has increased their emissions and, consequently, that they are subject to stringent NSR requirements under the Clean Air Act.

In August 2007, LG&E received information requests for the Mill Creek and Trimble County plants, but has received no further communications from the EPA since providing its responses. LG&E cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any.

States and environmental groups also have commenced litigation alleging violations of the NSR regulations by coal-fired generating plants across the nation. If LG&E is found to have violated NSR regulations by significantly increasing pollutants through a major plant modification, it would, among other things, be required to meet stringent permit limits reflecting Best Available Control Technology (BACT) for pollutants meeting the National Ambient Air Quality Standards (NAAQS) in the area and reflecting Lowest Achievable Emission Rates (LAER) for pollutants not meeting the NAAQS in the area. The costs to meet such limits, including installation of technology at certain units, could be significant.

TC2 Air Permit

The Sierra Club and other environmental groups petitioned the Kentucky Environmental and Public Protection Cabinet to overturn the air permit issued for the TC2 baseload generating unit, but the agency upheld the permit in an order issued in September 2007. In response to subsequent petitions by environmental groups, the EPA ordered certain non-material changes to the permit which, in January 2010, were incorporated into a final revised permit issued by the KDAQ. In March 2010, the environmental groups petitioned the EPA to object to the revised state permit. Until the EPA issues a final ruling on the pending petition and all available appeals are exhausted, LG&E cannot predict the outcome of this matter or the potential impact on the capital costs of this project, if any.

Cane Run Environmental Claims

In the 2011 to 2013 time period, the Louisville Metro Air Pollution Control District issued several notices of violation alleging violations of local air quality rules at the Cane Run plant. In November 2013, LG&E entered into a settlement resolving the pending citations in return for payment of a civil penalty in a non-material amount and performance of remedial measures not expected to result in material costs.

On September 6, 2013, LG&E received a letter on behalf of two residents adjacent to the Cane Run plant notifying various federal, state, and local agencies of their intent to file a citizen suit for alleged violations of the Clean Air Act (CAA) and Resource Conservation and Recovery Act (RCRA). On December 16, 2013, six residents, on behalf of themselves and others similarly situated, filed a class action complaint against LG&E in the U.S. District Court for the Western District of Kentucky for alleged violations of the CAA and RCRA. In addition, these plaintiffs assert common law claims of nuisance, trespass, and negligence. These plaintiffs seek injunctive relief and civil penalties that would accrue to governmental agencies, plus costs and attorney fees, for the alleged statutory violations. Under the common law claims, these plaintiffs seek monetary compensation and punitive damages for property damage and diminished property values for a class consisting of residents within four miles of the plant. In their individual capacities, these plaintiffs seek compensation for alleged adverse health effects. LG&E cannot predict the outcome of this matter or the potential impact on operations of the Cane Run plant. LG&E has previously announced that it anticipates retiring the coal-fired units at Cane Run before the end of 2015.

GHG Regulations and Tort Litigation

As a result of the April 2007 U.S. Supreme Court decision that the EPA has authority under the Clean Air Act to regulate GHG emissions from new motor vehicles, in April 2010, the EPA and the U.S. Department of Transportation issued new light-duty vehicle emissions standards that applied beginning with 2012 model year vehicles. The EPA also clarified that this standard, beginning in 2011, authorized regulation of GHG emissions from stationary sources under the NSR and Title V operating permit provisions of the Clean Air Act. As a result, any new sources or major modifications to existing GHG sources causing a net significant emissions increase now require adherence to the BACT permit limits for GHGs. The rules were challenged, and in June 2012 the D.C. Circuit Court upheld the EPA's regulations. In December 2012, the D.C. Circuit Court denied petitions for rehearing pertaining to its June 2012 opinion. On October 15, 2013, the U.S. Supreme Court granted certiorari for several petitions to decide whether the NSR provisions of the Clean Air Act require the EPA to regulate GHG emissions from stationary sources, such as power plants.

In June 2013, President Obama released his Climate Action Plan which reiterates the goal of reducing greenhouse gas emissions in the U.S. "in the range of" 17% below 2005 levels by 2020 through such actions as regulating power plant emissions, promoting increased use of renewables and clean energy technology, and establishing tighter energy efficiency standards. Also, by Presidential Memorandum the EPA was directed to issue a revised proposal for new power plants (a prior proposal was issued in 2012) by September 20, 2013, with a final rule in a timely fashion thereafter, and to issue proposed standards for existing plants by June 1, 2014 with a final rule to be issued by June 1, 2015. The EPA was further directed to require that states develop implementation plans for existing plants by June 2016. Regulation of existing plants could have a significant industry-wide impact depending on the structure and stringency of the final rule and the state implementation plans. The Administration's recent increase in its estimate of the "social cost of carbon" (which is used to calculate benefits associated with proposed regulations) from $23.80 to $38 per metric ton in 2015 may also lead to more costly regulatory requirements; the White House Office of Management and Budget (OMB) has opened this issue for public comment. Additionally, the Climate Action Plan requirements related to preparing the U.S. for the impacts of climate change could affect LG&E and others in the industry as modifications to electricity delivery systems to improve the ability to withstand major storms may be needed in order to meet those requirements.

The EPA issued its revised proposal for new sources on September 20, 2013 as directed by the White House. This proposal was published in the Federal Register on January 8, 2014, with comments due on March 10, 2014. Unlike the EPA's prior proposal, the EPA's revised proposal established separate emission standards for coal and gas units based on the application of different technologies. The coal standard is based on the application of partial carbon capture and sequestration technology, but because this technology is not presently commercially available, the revised proposal effectively precludes the construction of new coal plants. The EPA proposed the same standard for NGCC power plants as was proposed in 2012 and may not be consistently achievable. In addition, the EPA deleted the explicit exemption previously proposed for simple-cycle natural gas plants.

In November 2008, the Governor of Kentucky issued a comprehensive energy plan including non-binding targets aimed at promoting improved energy efficiency, development of alternative energy, development of carbon capture and sequestration projects, and other actions to reduce GHG emissions. In December 2009, the Kentucky Climate Action Plan Council was established to develop an action plan addressing potential GHG reductions and related measures. In November 2011, the Council issued a final report to the Secretary of Kentucky's Energy and Environment Cabinet for his consideration. The final report acknowledged that the recommendations would require additional review and analysis prior to implementation, and that many of the recommendations would likely require, in part, further legislative or regulatory actions. The impact of any such plan is not now determinable, but the costs to comply with the plan could be significant.

A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting plants and, although the decided cases to date have not sustained claims brought on the basis of these theories of liability, the law remains unsettled on these claims. In September 2009, the U.S. Court of Appeals for the Second Circuit in the case of AEP v. Connecticut reversed a federal district court's decision and ruled that several states and public interest groups, as well as the City of New York, could sue five electric utility companies under federal common law for allegedly causing a public nuisance as a result of their emissions of GHGs. In June 2011, the U.S. Supreme Court overturned the Second Circuit and held that such federal common law claims were displaced by the Clean Air Act and regulatory actions of the EPA. In addition, in Comer v. Murphy Oil (Comer case), the U.S. Court of Appeals for the Fifth Circuit (Fifth Circuit) declined to overturn a district court ruling that plaintiffs did not have standing to pursue state common law claims against companies that emit GHGs. The complaint in the Comer case named the previous indirect parent of LKE as a defendant based upon emissions from the Kentucky plants. In January 2011, the Supreme Court denied a petition to reverse the Fifth Circuit's ruling. In May 2011, the plaintiffs in the Comer case filed a substantially similar complaint in federal district court in Mississippi against 87 companies, including four of LG&E’s affiliates but excluding LG&E, under a Mississippi statute that allows the re-filing of an action in certain circumstances. In March 2012, the Mississippi federal district court granted defendants' motions to dismiss the state common law claims. Plaintiffs appealed to the U.S. Court of Appeals for the Fifth Circuit, and in May 2013, the Fifth Circuit affirmed the district court's dismissal of the case. Additional litigation in federal and state courts over such issues is continuing. LG&E cannot predict the outcome of these lawsuits or estimate a range of reasonably possible losses, if any.

In 2013, LG&E and its jointly owned power plants emitted approximately 17 million tons of carbon dioxide compared with 18 million tons in 2012. All tons are U.S. short tons (2,000 pounds/ton).

Renewable Energy Legislation

There has been interest in renewable energy legislation at both the state and federal levels. Federal legislation on renewable energy is not expected to be enacted this year.

LG&E believes there are financial, regulatory and logistical uncertainties related to the implementation of renewable energy mandates that will need to be resolved before the impact of such requirements on them can be estimated. Such uncertainties, among others, include the need to provide back-up supply to augment intermittent renewable generation, potential generation over-supply and downward pressure on energy prices that could result from such renewable generation and back-up, impacts to PJM's capacity market and the need for substantial changes to transmission and distribution systems to accommodate renewable energy sources. These uncertainties are not directly addressed by proposed legislation. LG&E cannot predict at this time the effect of renewable energy mandates that may be adopted, although the costs to implement and comply with any such requirements could be significant.

Water/Waste

Coal Combustion Residuals (CCRs)

In June 2010, the EPA proposed two approaches to regulating the disposal and management of CCRs (as either hazardous or non-hazardous) under the Resource Conservation and Recovery Act (RCRA). CCRs include fly ash, bottom ash and sulfur dioxide scrubber wastes. Regulating CCRs as a hazardous waste under Subtitle C of the RCRA would materially increase costs and result in early retirements of many coal-fired plants, as it would require plants to retrofit their operations to comply with full hazardous waste requirements for the generation of CCRs and associated waste waters through generation, transportation and disposal. This would also have a negative impact on the beneficial use of CCRs and could eliminate existing markets for CCRs. The EPA's proposed approach to regulate CCRs as non-hazardous waste under Subtitle D of the RCRA would mainly affect disposal and most significantly affect any wet disposal operations. Under this approach, many of the current markets for beneficial uses would not be affected. Currently, LG&E expects that several of its plants could be significantly impacted by the EPA's proposed non-hazardous waste regulations, as these plants are using surface impoundments for management and disposal of CCRs.

The EPA has issued information requests on CCR management practices at numerous plants throughout the power industry as it considers whether or not to regulate CCRs as hazardous waste. LG&E has provided information on CCR management practices at most of its plants in response to the EPA's requests. In addition, the EPA has conducted follow-up inspections to evaluate the structural stability of CCR management facilities at several plants and has implemented or is implementing certain actions in response to recommendations from these inspections.

The EPA is continuing to evaluate the unprecedented number of comments it received on its June 2010 proposed regulations. In October 2011, the EPA issued a Notice of Data Availability (NODA) requesting comments on selected documents it received during the comment period for the proposed regulations. In September 2013, in response to the proposed Effluent Limitation Guidelines, PPL submitted comments on the proposed CCR regulations. Also, in September 2013, PPL commented on a second CCR NODA seeking comment on additional information related to the EPA's proposal.

A coalition of environmental groups and two CCR recycling companies have filed lawsuits against the EPA seeking a deadline for final rulemaking and, in settlement of that litigation, the EPA has agreed to issue its final rulemaking by the end of 2014.

In July 2013, the U.S. House of Representatives passed House Bill H.R. 2218, the Coal Residuals and Reuse Management Act of 2013, which would preempt the EPA from issuing final CCR regulations and would set non-hazardous CCR standards under RCRA and authorize state permit programs. It remains uncertain whether similar legislation will likely be passed by the U.S. Senate. LG&E cannot predict at this time the final requirements of the EPA's CCR regulations or potential changes to the RCRA and what impact they would have on its facilities, but the financial and operational impact is expected to be material if CCRs are regulated as hazardous waste and significant if regulated as non-hazardous.

Trimble County Landfill Permit

In May 2011, LG&E submitted an application for a special waste landfill permit to handle coal combustion residuals generated at the Trimble County plant. After extensive review of the permit application in May 2013, the Kentucky Division of Waste Management denied the permit application on the grounds that the proposed facility would violate the Kentucky Cave Protection Act because it would eliminate an on-site karst feature considered to be a cave. After assessing additional options for managing coal combustion residuals, in January 2014, LG&E submitted to the Kentucky Division of Waste Management a landfill permit application for an alternate site adjacent to the plant. LG&E and KU are unable to determine the precise impact of this matter until a landfill permit is issued and any resulting legal challenges are concluded.

Seepages and Groundwater Infiltration

Seepages or groundwater infiltration has been detected at active and retired wastewater basins and landfills at various LG&E plants. LG&E has completed or is completing assessments of seepages or groundwater infiltration at various facilities and has completed or is working with agencies to implement assessment or abatement measures, where required. A range of reasonably possible losses cannot currently be estimated.

Clean Water Act 316(b)

The EPA published proposed rule 316(b) for existing facilities in April 2011. The EPA has been evaluating the comments it received to the proposed rule and meeting with industry groups to discuss options. The proposed rule contains two requirements to reduce impact to aquatic organisms at cooling water intake structures. The first requires all existing facilities to meet standards for the reduction of mortality of aquatic organisms that become trapped against water intake screens (impingement) regardless of the levels of mortality actually occurring or the cost to achieve the standards. The second requirement is to determine and install the best technology available to reduce mortality of aquatic organisms pulled through a plant's cooling water system (entrainment). A form of cost-benefit analysis is allowed for this second requirement involving a site-specific evaluation based on nine factors, including impacts to energy delivery reliability and the remaining useful life of the plant. The final rule is expected by April 17, 2014. Until the final rule is issued, LG&E cannot estimate a range of reasonably possible costs, if any, that would be required to comply with such a regulation.

Effluent Limitations Guidelines (ELGs) and Standards

In June 2013, the EPA published proposed regulations to revise discharge limitations for steam electric generation wastewater permits. The proposed limitations are based on the EPA review of available treatment technologies and their capacity for reducing pollutants and include new requirements for fly ash and bottom ash transport water and metal cleaning waste waters, as well as new limits for scrubber wastewater and landfill leachate. The EPA's proposed ELG regulations contain requirements that would affect the inspection and operation of CCR facilities, if finalized. The EPA has indicated that it will coordinate these regulations with the regulation of CCRs discussed above. The proposal contains alternative approaches, some of which could significantly impact LG&E’s coal-fired plants. LG&E worked with industry groups to comment on the proposed regulation on September 20, 2013. The final regulation is expected to be issued in May 2014 but it may be delayed. At the present time, LG&E is unable to predict the outcome of this matter or estimate a range of reasonably possible costs, but the costs could be significant. Pending finalization of the ELGs, certain states and environmental groups (including Kentucky) are proposing more stringent technology-based limits in permit renewals. Depending on the final limits imposed, the costs of compliance could be significant and costs could be imposed ahead of federal timelines.

Other Issues

The EPA is reassessing its polychlorinated biphenyls (PCB) regulations under the Toxic Substance Control Act, which currently allow certain PCB articles to remain in use. In April 2010, the EPA issued an Advanced Notice of Proposed Rulemaking for changes to these regulations. This rulemaking could lead to a phase-out of all or some PCB-containing equipment. The EPA is planning to propose the revised regulations in November 2014. PCBs are found, in varying degrees, in LG&E’s operations. LG&E cannot predict at this time the outcome of these proposed EPA regulations and what impact, if any, they would have on its facilities, but the costs could be significant.

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County plant. In November 2010, the Cabinet issued a final order upholding the permit. In December 2010, the environmental groups appealed the order to the Trimble Circuit Court, but the case was subsequently transferred to the Franklin Circuit Court. In September 2013, the court reversed the Cabinet order upholding the permit and remanded the permit to the agency for further proceedings. In October 2013, LG&E filed a notice of appeal with the Kentucky Court of Appeals. LG&E is unable to predict the outcome of this matter or estimate a range of reasonably possible losses, if any.

The EPA and the Army Corps of Engineers are working on a guidance document that will expand the federal government's interpretation of what constitutes "waters of the U.S." subject to regulation under the Clean Water Act. This change has the potential to affect generation and delivery operations, with the most significant effect being the potential elimination of the existing regulatory exemption for plant waste water treatment systems. The costs that may be imposed on LG&E as a result of any eventual expansion of this interpretation cannot reliably be estimated at this time but could be significant.

Superfund and Other Remediation

LG&E is remediating or has completed the remediation of several sites that were not addressed under a regulatory program such as Superfund, but for which LG&E may be liable for remediation. These include a number of former coal gas manufacturing plants previously owned or operated or currently owned by predecessors or affiliates of LG&E. There are additional sites, formerly owned or operated by LG&E

predecessors or affiliates, for which LG&E lacks information on current site conditions and is therefore unable to predict what, if any, potential liability they may have.

Depending on the outcome of investigations at sites where investigations have not begun or been completed or developments at sites for which LG&E currently lacks information, the costs of remediation and other liabilities could be material. LG&E cannot estimate a range of reasonably possible losses, if any, related to these matters.

The EPA is evaluating the risks associated with polycyclic aromatic hydrocarbons and naphthalene, chemical by-products of coal gas manufacturing. As a result of the EPA's evaluation, individual states may establish stricter standards for water quality and soil cleanup. This could require LG&E to take more extensive assessment and remedial actions at former coal gas manufacturing plants. LG&E cannot estimate a range of reasonably possible losses, if any, related to these matters.

From time to time, LG&E undertakes remedial action in response to spills or other releases at various on-site and off-site locations, negotiates with the EPA and state and local agencies regarding actions necessary for compliance with applicable requirements, negotiates with property owners and other third parties alleging impacts from LG&E’s operations and undertakes similar actions necessary to resolve environmental matters which arise in the course of normal operations. Based on analyses to date, resolution of these environmental matters is not expected to have a significant adverse impact on LG&E’s operations.

Future cleanup or remediation work at sites currently under review, or at sites not currently identified, may result in significant additional costs for LG&E.

Other

Labor Unions

In 2014, certain labor agreement negotiations are scheduled to begin. For LG&E, negotiations with the IBEW will begin in October 2014. The current agreement expires in November 2014. LG&E cannot predict the outcome of the union labor negotiations.

The labor agreement expiring in 2014 covered 701 employees at December 31, 2013, which is 70% of LG&E’s total workforce.

Guarantees and Other Assurances

In the normal course of business, LG&E 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 the creditworthiness attributed to a subsidiary on a stand-alone basis or to facilitate the commercial activities in which these subsidiaries engage.

Pursuant to the OVEC power purchase contract, LG&E 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 currently included within a demand charge designed to cover these costs over the term of the contract. LG&E's proportionate share of OVEC's outstanding debt was $89 million at December 31, 2013. The maximum exposure and the expiration date of these potential obligations are not presently determinable. See "Energy Purchases Commitments" above for additional information on the OVEC power purchase contract.

LG&E provides other miscellaneous guarantees through contracts entered into in the normal course of business. These guarantees are primarily in the form of indemnification or warranties related to services or equipment and vary in duration. The amounts of these guarantees often are not explicitly stated, and the overall maximum amount of the obligation under such guarantees cannot be reasonably estimated. Historically, no significant payments have been made with respect to these types of guarantees and the probability of payment/performance under these guarantees is remote.

PPL, on behalf of itself and certain of its subsidiaries including LG&E, 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

LG&E and KU jointly dispatch their generation units with the lowest cost generation used to serve their retail customers. When LG&E has excess generation capacity after serving its own retail customers and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail customers and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are reflected in the Statements of Income as "Electric revenue from affiliate" and "Energy purchases from affiliate" and are recorded at a price equal to the seller's fuel cost. Savings realized from such intercompany transactions are shared equally between 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 LG&E with administrative, management and support services. Where applicable, the costs of these services are charged to LG&E as direct support costs. General costs that cannot be directly attributed to LG&E are allocated and charged as indirect support costs. LKS bases its indirect allocations on LG&E’s number of employees, total assets, revenues, number of customers and/or other statistical information. LKS charged the following amounts for the years ended December 31, and believe these amounts are reasonable, including amounts applied to accounts that are further distributed between capital and expense.

2013	2012
$ 216	$ 186

LG&E and KU also provide services to each other and to LKS. Billings between LG&E and KU relate to labor and overheads associated with union and hourly employees performing work for the other company, charges related to jointly-owned generating units and other miscellaneous charges. Tax settlements between LKE and LG&E are reimbursed through LKS.

Intercompany Derivatives

Periodically, LG&E 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. See Note 14 for additional information on intercompany derivatives.

Other

See Note 1 for discussions regarding the intercompany tax sharing agreement and Note 5 for a discussion regarding capital transactions by LG&E. See Note 8 for discussions regarding intercompany allocations associated with defined benefits.

12. Other Income (Expense) – net

The components of "Other Income (Expense) - net" for 2013 and 2012 for LG&E were not significant.

13. Fair Value Measurements and Credit Concentration

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). 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 2013 and 2012, 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, 2013			
	Total	Level 1	Level 2	Level 3
Assets				
Cash and cash equivalents	$ 8	$ 8	$ -	$ -
Restricted cash and cash equivalents (a)	22	22	-	-
Total assets	$ 30	$ 30	$ -	$ -
Liabilities				
Price risk management liabilities:				
Interest rate swaps	$ 36	$ -	$ 36	$ -
Total liabilities	$ 36	$ -	$ 36	$ -

	December 31, 2012			
	Total	Level 1	Level 2	Level 3
Assets				
Cash and cash equivalents	$ 22	$ 22	$ -	$ -
Restricted cash and cash equivalents (a)	32	32	-	-
Price risk management assets:				
Interest rate swaps	7	-	7	-
Total assets	$ 61	$ 54	$ 7	$ -
Liabilities				
Price risk management liabilities:				
Interest rate swaps	$ 58	$ -	$ 58	$ -
Total liabilities	$ 58	$ -	$ 58	$ -

(a) Included in "Other noncurrent assets" on the Balance Sheets.

Price Risk Management Assets/Liabilities - Interest Rate Swaps

To manage interest rate risk, LG&E 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) 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. Accounting personnel, who report to the CFO, interpret analysis quarterly to classify the contracts in the fair value hierarchy. Valuation techniques are evaluated periodically.

Financial Instruments Not Recorded at Fair Value

The carrying amounts of long-term debt on the Balance Sheets and its 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 the credit risk of LG&E. These instruments are classified as Level 2. The effect of third-party credit enhancements is not included in the fair value measurement.

	December 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 1,353	$ 1,372	$ 1,112	$ 1,178

The carrying value of short-term debt (including notes between affiliates), when outstanding, approximates fair value due to the variable interest rates associated with the short-term debt and is classified as Level 2.

Credit Concentration Associated with Financial Instruments

Contracts are entered into with many entities for the purchase and sale of energy. When NPNS is elected, the fair value of these contracts is not reflected in the financial statements. However, the fair value of these contracts is considered when committing to new business from a credit perspective. See Note 14 for information on credit policies used to manage credit risk, including master netting arrangements and collateral requirements.

At December 31, 2013, LG&E's credit exposure was not significant.

14. Derivative Instruments and Hedging Activities

Risk Management Objectives

PPL has a risk management policy approved by the Board of Directors to manage market risk (including price, liquidity and volumetric risk) and credit risk (including non-performance risk and payment default risk). Senior 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 and market prices, and verification of risk and transaction limits.

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 the contracts meet the definition of a derivative. All derivatives are recognized on the Balance Sheets at their fair value, unless NPNS is elected. The table below summarizes the market risks that affect LG&E.

Commodity price risk (including basis and volumetric risk)	M
Interest rate risk:	
Debt issuances	M
Defined benefit plans	M
Equity securities price risk:	
Defined benefit plans	M

M = The regulatory environment, by definition, significantly mitigates market risk.

Commodity price risk

LG&E's rates include certain mechanisms for fuel, gas supply and environmental expenses. These mechanisms generally provide for timely recovery of market price and volumetric fluctuations associated with these expenses.

Interest rate risk

LG&E is exposed to interest rate risk associated with forecasted fixed-rate and existing floating-rate debt issuances. LG&E utilizes over-the-counter interest rate swaps to limit exposure to market fluctuations on floating-rate debt and utilizes forward starting interest rate swaps to hedge changes in benchmark interest rates in connection with future debt issuances.

Credit Risk

Credit risk is the potential loss that may be incurred due to a counterparty's non-performance.

LG&E is exposed to credit risk from interest rate derivatives with third-party financial institutions.

The majority of LG&E’s credit risk stems from energy sales and purchases. In the event a supplier of LG&E defaults on its obligation, it would be required to seek replacement power or replacement fuel in the market. In general, incremental costs incurred by LG&E would be recoverable from customers in future rates, thus mitigating the financial risk for these entities.

LG&E 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. LG&E 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.

Master Netting Arrangements

Net derivative positions on the balance sheets are not offset against the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

LG&E had no obligation to return cash collateral under master netting arrangements at December 31, 2013 and 2012.

LG&E had posted cash collateral under master netting arrangements of $22 million and $32 million at December 31, 2013 and 2012.

See "Offsetting Derivative Investments" below for a summary of derivative positions presented in the balance sheets where a right of setoff exists under these arrangements.

Interest Rate Risk

LG&E issues debt to finance its operations, which exposes it to interest rate risk. Various financial derivative instruments are utilized to adjust the mix of fixed and floating interest rates in its debt portfolio, adjust the duration of the debt portfolio and lock in benchmark interest rates in anticipation of future financing, when appropriate. Risk limits under the risk management program are designed to balance risk exposure to volatility in interest expense and changes in the fair value of the debt portfolio due to changes in benchmark interest rates.

Cash Flow Hedges

In November 2012 and April 2013, LG&E entered into forward-starting interest rate swaps with PPL that hedged the interest payments on new debt that was expected to be issued in 2013. In September 2013, these hedges were terminated and LG&E entered into new forward-starting interest rate swaps with PPL, effectively extending the start date of the prior hedges from September 2013 to December 2013. All of these swaps had terms identical to forward-starting swaps entered into by PPL with third parties. New debt totaling $250 million was issued in November 2013 and the hedges issued in September were terminated in November 2013. Net cash settlements of $43 million were received on the swaps that were terminated in September and November, which are included in "Cash Flows from Operating Activities" on the Statement of Cash Flows. Realized gains and losses on these swaps are probable of recovery through regulated rates; as such, the net settlements were reclassified from AOCI to regulatory liabilities and are being recognized in "Interest Expense" on the Statements of Income over the life of the newly issued debt. For 2013, there was no hedge ineffectiveness recorded for the interest rate derivatives.

Economic Activity

LG&E enters into interest rate swap contracts that economically hedge interest payments on variable rate debt. Because realized gains and losses from the swaps, including a terminated swap contract, are recoverable through regulated rates, any subsequent changes in fair value of these derivatives are included in regulatory assets or liabilities until they are realized as interest expense. Realized gains and losses are recognized in "Interest Expense" on the Statements of Income when the hedged transaction occurs. At December 31, 2013, LG&E held contracts with a notional amount of $179 million that range in maturity through 2033.

Accounting and Reporting

All derivative instruments are recorded at fair value on the Balance Sheets as an asset or liability unless NPNS is elected. Changes in the fair value of derivatives not designated as NPNS are recognized currently in earnings unless specific hedge accounting criteria are met and designated as such, except for the change in fair value of LG&E's interest rate swaps that are recognized as regulatory assets or regulatory liabilities. See Note 4 for amounts recorded in regulatory assets and regulatory liabilities at December 31, 2013 and 2012.

See Note 1 for additional information on accounting policies related to derivative instruments.

The following table presents the fair value and the location on the Balance Sheets of derivative instruments designated as cash flow hedges.

	December 31, 2013		December 31, 2012	
	Assets	Liabilities	Assets	Liabilities
Current:				
Price Risk Management Assets/Liabilities (a):				
Interest rate swaps	$ -	$ -	$ 7	$ -

(a) Represents the location on the Balance Sheets.

The following table presents the pre-tax effect of derivative instruments designated as cash flow hedges that are recognized in regulatory liabilities.

Derivative Instruments	Location of Gain (Loss)	2013	2012
Interest rate swaps	Regulatory liabilities - noncurrent	$ 36	$ 7

The following table presents the fair value and the location on the Balance Sheets of derivatives not designated as hedging instruments.

	December 31, 2013		December 31, 2012	
	Assets	**Liabilities**	**Assets**	**Liabilities**
Current:				
Other Current Assets/Liabilities (a):				
Interest rate swaps	$ -	$ 4	$ -	$ 5
Total current	-	4	-	5
Noncurrent:				
Price Risk Management Assets/Liabilities (a):				
Interest rate swaps	-	32	-	53
Total noncurrent	-	32	-	53
Total derivatives	$ -	$ 36	$ -	$ 58

(a) Represents the location on the Balance Sheets.

The following tables present the pre-tax effect of derivatives not designated as cash flow hedges that are recognized in income or regulatory assets.

Derivative Instruments	**Location of Gain (Loss)**	**2013**	**2012**
Interest rate swaps	Interest Expense	$ (8)	$ (8)
Commodity contracts	Operating Revenues	-	-
	Total	$ (8)	$ (8)

Derivative Instruments	**Location of Gain (Loss)**	**2013**	**2012**
Interest rate swaps	Regulatory assets - noncurrent	$ 22	$ 1

Offsetting Derivative Instruments

LG&E has master netting arrangements or similar agreements in place including derivative clearing agreements with futures commission merchants (FCMs) to permit the trading of cleared derivative products on one or more futures exchanges. The clearing arrangements permit an FCM to use and apply any property in its possession as a set off to pay amounts or discharge obligations owed by a customer upon default of the customer and typically do not place any restrictions on the FCM's use of collateral posted by the customer. LG&E also enters into agreements pursuant to which it trades 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 setoff 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.

LG&E 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. The tables below summarize the derivative positions presented in the balance sheets where a right of setoff exists under these arrangements and related cash collateral received or pledged.

	Assets			
		Eligible for Offset		
	Gross	Derivative Instruments	Cash Collateral Received	Net
December 31, 2012				
Treasury derivatives	$ 7	$ -	$ -	$ 7

	Liabilities			
		Eligible for Offset		
	Gross	Derivative Instruments	Cash Collateral Received	Net
December 31, 2013				
Treasury derivatives	$ 36	$ -	$ 20	$ 16
December 31, 2012				
Treasury derivatives	$ 58	$ -	$ 30	$ 28

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 the credit ratings of LG&E. 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 the credit rating at levels that remain above investment grade. In either case, if the applicable credit rating were to fall below investment grade (i.e., below BBB- for S&P or Fitch, or Baa3 for Moody's), and assuming no assignment to an investment grade affiliate were allowed, most of these credit contingent 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.

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 the performance of LG&E's obligation under the contract. A counterparty demanding adequate assurance could require a transfer of additional collateral or other security, including letters of credit, cash and guarantees from a creditworthy entity. This would typically involve negotiations among the parties. However, amounts disclosed below represent assumed immediate payment or immediate and ongoing full collateralization for derivative instruments in net liability positions with "adequate assurance" features.

At December 31, 2013, the effect of a decrease in credit ratings below investment grade on derivative contracts that contain credit risk-related contingent features and were in a net liability position is summarized as follows:

Aggregate fair value of derivative instruments in a net liability position with credit risk-related contingent provisions	$	26
Aggregate fair value of collateral posted on these derivative instruments		22
Aggregate fair value of additional collateral requirements in the event of a credit downgrade below investment grade (a)		6

(a) Includes the effect of net receivables and payables already recorded on the Balance Sheets.

15. Other Intangible Assets

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2013				December 31, 2012			
	Gross Carrying Amount		Accumulated Amortization		Gross Carrying Amount		Accumulated Amortization	
Subject to amortization:								
Coal contracts (a)	$	124	$	81	$	124	$	62
Land and transmission rights		7		1		8		1
Emission allowances (b)		1		-		1		-
OVEC power purchase agreement (c)		87		17		87		13
Total subject to amortization	$	219	$	99	$	220	$	76

(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 is being amortized over the same period as the intangible assets, eliminating any income statement impact. See Note 4 for additional information.

(b) Represents the fair value at the acquisition date of emission allowances recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability is recorded related to these emission allowances, which is being amortized as the emission allowances are consumed, eliminating any income statement impact. Consumption related to these emission allowances was insignificant in 2013 and in 2012.

(c) 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. See Note 4 for additional information.

Current intangible assets are included in "Other current assets" on the Balance Sheets. Long-term intangible assets are presented as "Other intangibles" on the Balance Sheets.

Amortization expense, excluding consumption of emission allowances, was as follows:

	2013	2012
Intangible assets with regulatory offset	23	23
Total	$ 23	$ 23

Amortization expense for each of the next five years, excluding consumption of emission allowances, is estimated to be:

	2014	2015	2016	2017	2018
Intangibles with regulatory offset	$ 23	$ 24	$ 13	$ 6	$ 6

16. Asset Retirement Obligations

LG&E's AROs are primarily related to the final retirement of assets associated with generating units. LG&E also has AROs related to natural gas mains and wells. LG&E's transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, no material AROs are recorded for transmission and distribution assets. As described in Notes 1 and 4, LG&E's accretion and depreciation expense are recorded as a regulatory asset, such that there is no earnings impact. In 2013, AROs were revalued primarily due to updates in the estimated cash flows for ash ponds and CCR surface impoundments based on updated cost estimates.

The changes in the carrying amounts of AROs were as follows.

	2013	2012
ARO at beginning of period	$ 62	$ 57
Accretion expense	3	3
Changes in estimated cash flow or settlement date	17	5
Obligations settled	(8)	(3)
ARO at end of period	74	62

Substantially all of the ARO balances are classified as noncurrent at December 31, 2013 and 2012.

17. New Accounting Guidance Pending Adoption

Accounting for Obligations Resulting from Joint and Several Liability Arrangements

Effective January 1, 2014, LG&E will retrospectively adopt accounting guidance for the recognition, measurement and disclosure of certain obligations resulting from joint and several liability arrangements when the amount of the obligation is fixed at the reporting date. If the obligation is determined to be in the scope of this guidance, it will be measured as the sum of the amount the reporting entity agreed to pay on the basis of its arrangements among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. This guidance also requires additional disclosures for these obligations.

The adoption of this guidance is not expected to have a significant impact on LG&E.

Presentation of Unrecognized Tax Benefits When Net Operating Loss Carryforwards, Similar Tax Losses, or Tax Credit Carryforwards Exist

Effective January 1, 2014, LG&E will prospectively adopt accounting guidance that requires an unrecognized tax benefit, or a portion of an unrecognized tax benefit, to be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward. To the extent a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, or the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose, the unrecognized tax benefit should be presented in the financial statements as a liability and should not be combined with deferred tax assets.

The adoption of this guidance is not expected to have a significant impact on LG&E.

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18. Notes to Statement of Cash Flows

Supplemental disclosures of cash flow information.

	December 31, 2013	December 31, 2012
Cash paid during the period for:		
Income taxes	$ 51	$ 5
Interest on borrowed money	28	29
Other cash paid for interest	8	9

19. Notes to Statement of Income for the Year

See page 115, line 6, column (g). Electric Utility Depreciation Expense includes $8 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 6, column (i). Gas Utility Depreciation Expense includes $3 million applicable to Common Utility Plant apportioned to Gas Operations.

See page 115, line 8, column (g). Electric Utility Amortization and Depletion of Utility Plant includes $6 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 8, column (i). Gas Utility Amortization and Depletion of Utility Plant includes $2 million applicable to Common Utility Plant apportioned to Gas Operations.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1				[redacted]	[redacted]
2				[redacted]	[redacted]
3				[redacted]	[redacted]
4				123,106,208	123,106,208
5				[redacted]	[redacted]
6				[redacted]	[redacted]
7				[redacted]	[redacted]
8				[redacted]	[redacted]
9				163,405,117	163,405,117
10				[redacted]	[redacted]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	4,922,870,818	3,895,298,143
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	139,519,260	87,809,623
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,062,390,078	3,983,107,766
9	Leased to Others		
10	Held for Future Use	5,523,196	5,523,196
11	Construction Work in Progress	651,432,116	575,597,121
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,719,345,390	4,564,228,083
14	Accum Prov for Depr, Amort, & Depl	2,304,132,232	1,925,796,828
15	Net Utility Plant (13 less 14)	3,415,213,158	2,638,431,255
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,273,475,442	1,925,766,839
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights	41	
21	Amort of Other Utility Plant	30,626,760	
22	Total In Service (18 thru 21)	2,304,102,243	1,925,766,839
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	29,989	29,989
29	Amortization		
30	Total Held for Future Use (28 & 29)	29,989	29,989
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,304,132,232	1,925,796,828

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
798,538,429				229,034,246	3
					4
					5
44,112,888				7,596,749	6
					7
842,651,317				236,630,995	8
					9
					10
55,354,723				20,480,272	11
					12
898,006,040				257,111,267	13
261,129,738				117,205,666	14
636,876,302				139,905,601	15
					16
					17
261,129,697				86,578,906	18
					19
41					20
				30,626,760	21
261,129,738				117,205,666	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
261,129,738				117,205,666	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	2,240	
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	2,240	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	6,416,587	385,814
9	(311) Structures and Improvements	327,126,222	819,302
10	(312) Boiler Plant Equipment	1,417,342,234	25,082,539
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	226,218,696	7,858,799
13	(315) Accessory Electric Equipment	180,465,607	-266,190
14	(316) Misc. Power Plant Equipment	17,149,906	1,646,504
15	(317) Asset Retirement Costs for Steam Production	32,595,958	16,539,678
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,207,315,210	52,066,446
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	6	
28	(331) Structures and Improvements	6,875,723	-871,338
29	(332) Reservoirs, Dams, and Waterways	14,446,087	-1,315,651
30	(333) Water Wheels, Turbines, and Generators	30,924,099	5,344,376
31	(334) Accessory Electric Equipment	7,406,038	-1,258,027
32	(335) Misc. Power PLant Equipment	1,240,269	-917,552
33	(336) Roads, Railroads, and Bridges	29,931	
34	(337) Asset Retirement Costs for Hydraulic Production	51,660	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	60,973,813	981,808
36	D. Other Production Plant		
37	(340) Land and Land Rights	8,133	5,015
38	(341) Structures and Improvements	15,004,440	
39	(342) Fuel Holders, Products, and Accessories	7,601,229	
40	(343) Prime Movers	160,999,649	2,873,317
41	(344) Generators	33,475,640	7,795
42	(345) Accessory Electric Equipment	21,341,231	161,346
43	(346) Misc. Power Plant Equipment	3,796,323	
44	(347) Asset Retirement Costs for Other Production	32,135	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	242,258,780	3,047,473
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,510,547,803	56,095,727

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			2,240		2
					3
					4
			2,240		5
					6
					7
			6,802,401		8
524,192		-25,088,103	302,333,229		9
5,121,553		25,088,103	1,462,391,323		10
					11
998,736			233,078,759		12
671,068			179,528,349		13
7,457			18,788,953		14
1,220,420			47,915,216		15
8,543,426			2,250,838,230		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			6		27
43,799			5,960,586		28
			13,130,436		29
201			36,268,274		30
			6,148,011		31
			322,717		32
			29,931		33
1,450			50,210		34
45,450			61,910,171		35
					36
			13,148		37
			15,004,440		38
			7,601,229		39
2,362,678			161,510,288		40
			33,483,435		41
57,671			21,444,906		42
			3,796,323		43
			32,135		44
2,420,349			242,885,904		45
11,009,225			2,555,634,305		46

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	10,884,232	
49	(352) Structures and Improvements	6,547,336	94,024
50	(353) Station Equipment	134,315,901	7,947,238
51	(354) Towers and Fixtures	41,122,522	-51,414
52	(355) Poles and Fixtures	53,885,087	6,888,230
53	(356) Overhead Conductors and Devices	47,917,481	1,283,344
54	(357) Underground Conduit	2,278,628	
55	(358) Underground Conductors and Devices	7,425,136	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	218,085	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	304,594,408	16,161,422
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,123,724	
61	(361) Structures and Improvements	6,136,930	605,468
62	(362) Station Equipment	116,854,800	4,049,753
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	148,236,338	11,998,674
65	(365) Overhead Conductors and Devices	250,501,076	12,528,325
66	(366) Underground Conduit	73,020,958	1,742,267
67	(367) Underground Conductors and Devices	153,856,164	8,298,159
68	(368) Line Transformers	143,116,094	3,253,993
69	(369) Services	29,003,102	1,077,287
70	(370) Meters	38,614,288	769,150
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	86,792,228	3,020,189
74	(374) Asset Retirement Costs for Distribution Plant	637,770	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,050,893,472	47,343,265
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights		
87	(390) Structures and Improvements		
88	(391) Office Furniture and Equipment		
89	(392) Transportation Equipment	8,569,173	116,363
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	4,853,528	185,486
92	(395) Laboratory Equipment		
93	(396) Power Operated Equipment	2,454,910	
94	(397) Communication Equipment	229,476	1,532,101
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	16,107,087	1,833,950
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	16,107,087	1,833,950
100	TOTAL (Accounts 101 and 106)	3,882,145,010	121,434,364
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	3,882,145,010	121,434,364

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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
			10,884,232		48
		-39,064	6,602,296		49
789,941		-90,500	141,382,698		50
84,626			40,986,482		51
154,719			60,618,598		52
286,924			48,913,901		53
			2,278,628		54
			7,425,136		55
					56
			218,085		57
1,316,210		-129,564	319,310,056		58
					59
			4,123,724		60
13,609		39,064	6,767,853		61
1,574,062		90,500	119,420,991		62
					63
928,003		2,132	159,309,141		64
1,851,319		-2,132	261,175,950		65
13,099			74,750,126		66
322,300			161,832,023		67
1,357,714			145,012,373		68
17,739			30,062,650		69
107,836			39,275,602		70
					71
					72
1,815,948			87,996,469		73
			637,770		74
8,001,629		129,564	1,090,364,672		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
					86
					87
					88
40,601			8,644,935		89
					90
			5,039,014		91
					92
103,943			2,350,967		93
			1,761,577		94
					95
144,544			17,796,493		96
					97
					98
144,544			17,796,493		99
20,471,608			3,983,107,766		100
					101
					102
					103
20,471,608			3,983,107,766		104

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 204 Line No.: 13 Column: c

Amounts temporarily classified to plant account Accessory Electric Equipment (315) in Completed Construction Not Classified - Electric (106) were reclassed to the correct plant account at the time of final unitization.

Schedule Page: 204 Line No.: 28 Column: c

Amounts temporarily classified to plant account Structures and Improvements (331) in Completed Construction Not Classified - Electric (106) were reclassed to the correct plant account at the time of final unitization.

Schedule Page: 204 Line No.: 29 Column: c

Amounts temporarily classified to plant account Reservoirs, Dams, and Waterways (332) in Completed Construction Not Classified - Electric (106) were reclassed to the correct plant account at the time of final unitization.

Schedule Page: 204 Line No.: 31 Column: c

Amounts temporarily classified to plant account Accessory Electric Equipment (334) in Completed Construction Not Classified - Electric (106) were reclassed to the correct plant account at the time of final unitization.

Schedule Page: 204 Line No.: 32 Column: c

Amounts temporarily classified to plant account Misc. Power Plant Equipment (335) in Completed Construction Not Classified - Electric (106) were reclassed to the correct plant account at the time of final unitization.

Schedule Page: 204 Line No.: 51 Column: c

Amounts temporarily classified to plant account Towers and Fixtures (354) in Completed Construction Not Classified - Electric (106) were reclassed to the correct plant account at the time of final unitization.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	Five Tracts in or near Louisville, Kentucky	Various	Various	372,352
3				
4	US 42: Tract No. D152	01/31/2000	2015-2020	253,321
5				
6	Fegenbush Lane at the General Electric Plant	05/01/2012	2018-2023	519,009
7				
8	Tucker Station Distribution Substation -			
9	Blankenbaker Station Business Park,			
10	Tract 13	07/01/2012	2015-2019	745,731
11				
12	Distribution Drive at Riverport	04/01/2013	2015-2019	839,535
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Site Development - Kentucky Street Substation D61			
23	and Kentucky Sub	06/30/1992	2015-2019	20,595
24				
25	Distribution Drive at Riverport	04/01/2013	2015-2019	2,772,653
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			5,523,196

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	MC4 FGD AND FABRIC FILTER	138,862,467
3	MC 1&2 FGD AND FABRIC FILTERS	109,690,406
4	MC3 FGD AND FABRIC FILTER	47,592,195
5	TC1 FABRIC FILTER	14,319,240
6	TC CCP LANDFILL PHASE 1 RAVINE - LGE	8,514,366
7	MC3 BURNERS REPLACEMENT	4,645,009
8	MC4 BURNERS REPLACEMENT	4,253,891
9	MC1 GENERATOR STATOR BAR	2,969,803
10	MC2 GENERATOR STATOR BAR	2,916,465
11	MC3 GENERATOR STATOR BAR	2,839,580
12	CR LANDFILL MSE WALL	2,790,265
13	MC GSU SPARE TRANSFORMER	2,587,124
14	TC2 CAPITAL SPARES - LGE	2,271,298
15	MC4 REHEATER	2,245,633
16	TC1 BOILER REHEATER FRONT PLATENS ASSEMBLY	1,176,749
17	MC4 SUPERHEATER PENDANTS	1,156,079
18	CR4 GENERATOR ROTOR REWIND	1,042,453
19	STEAM PRODUCTION MINOR	9,999,161
20		
21	HYDRAULIC POWER MAJOR	
22	OHIO FALLS REDEVELOPMENT UNIT #3	18,011,598
23	OHIO FALLS REDEVELOPMENT UNIT #1	12,257,079
24	OHIO FALLS REDEVELOPMENT UNIT #4	3,974,197
25	OHIO FALLS REDEVELOPMENT UNIT #2	3,973,557
26	OHIO FALLS REDEVELOPMENT UNIT #8	3,961,176
27	HYDRAULIC POWER MINOR	448,886
28		
29	OTHER PRODUCTION MAJOR	
30	CANE RUN UNIT #7 CCGT	89,858,247
31	GREEN RIVER UNIT #5 CCGT	1,443,648
32	OTHER PRODUCTION MINOR	2,438,659
33		
34	TRANSMISSION MAJOR	
35	MIDDLETOWN 345/138kV 448MVA TRANSFORMER	8,174,410
36	NEW 138kV CANE RUN 7 SWITCHYARD	6,069,373
37	PRIORITY REPLACEMENT TRANSMISSION LINES	3,656,733
38	CANE RUN 345kV TRANSFORMER - LGE	3,310,313
39	NEW 345kV BREAKER STATION - NEW ALBANY SUBSTATION	3,127,999
40	NEW 345kV BREAKER STATION - PADDY'S WEST/NORTHSIDE	2,364,150
41	MIDDLETOWN CONTROL HOUSE	2,204,243
42	LGE BREAKER REPLACEMENTS	1,906,375
43	TOTAL	575,597,121

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	NEW 138kV CR7 SWITCHYARD-INTERCONNECTION	1,692,698
2	CANE RUN CONTROL HOUSE - LGE	1,486,024
3	REPLACE 138kV BREAKERS AT CANE RUN & PADDY'S WEST	1,470,282
4	NERCALRT-NORTHSIDE-BEARGRASS	1,259,165
5	TRANSMISSION MINOR	8,768,686
6		
7	DISTRIBUTION MAJOR	
8	NETWORK TRANSFORMER PROTECTOR AUTOMATION PILOT	4,522,280
9	LGE POLE REPLACEMENT	3,516,351
10	LGE LINE TRANSFORMERS	2,558,693
11	LGE PORTABLE SUBSTATION	2,009,915
12	PAPER INSULATED CABLE REPLACEMENT	1,982,404
13	WORTHINGTON CIRCUIT WORK	1,475,537
14	PAPER INSULATED UG CABLE REPLACEMENT	1,466,350
15	DISTRIBUTION MINOR	16,335,909
16		
17		
18		
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42		
43	TOTAL	575,597,121

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,852,616,696	1,852,616,696		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	108,277,101	108,277,101		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	154,338	154,338		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	5	-29,984	29,989	
9	Fuel Stock	218,469	218,469		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	108,649,913	108,619,924	29,989	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	19,249,738	19,249,738		
13	Cost of Removal	21,525,292	21,525,292		
14	Salvage (Credit)	742,256	742,256		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	40,032,774	40,032,774		
16	Other Debit or Cr. Items (Describe, details in footnote):	5,784,863	5,784,863		
17					
18	Book Cost or Asset Retirement Costs Retired	-1,221,870	-1,221,870		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,925,796,828	1,925,766,839	29,989	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,241,257,024	1,241,227,035	29,989	
21	Nuclear Production				
22	Hydraulic Production-Conventional	9,583,477	9,583,477		
23	Hydraulic Production-Pumped Storage				
24	Other Production	81,530,809	81,530,809		
25	Transmission	142,356,664	142,356,664		
26	Distribution	439,637,927	439,637,927		
27	Regional Transmission and Market Operation				
28	General	11,430,927	11,430,927		
29	TOTAL (Enter Total of lines 20 thru 28)	1,925,796,828	1,925,766,839	29,989	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 219 Line No.: 4 Column: c

In August 2013, year-to-date regulatory offsets for depreciation on asset retirement cost assets and ARO liability accretion were reclassed from Regulatory Credits (407.4) to Depreciation Expense for Asset Retirement Costs (403.1) and Accretion Expense (411.10).

Schedule Page: 219 Line No.: 8 Column: c

Accrual for cost of removal and salvage for ARO parent assets (FERC 254 and 403).

Schedule Page: 219 Line No.: 8 Column: d

Depreciation on a facility not currently used in electric operations.

Schedule Page: 219 Line No.: 16 Column: c

The balance for the accrual for cost of removal and salvage for ARO parent assets was reclassed from Other Regulatory Liabilities (254) to Accumulated Provision for Depreciation of Electric Utility Plant (108)	$ 287,259
Accrual for depreciation on asset retirement costs (Other Regulatory Assets FERC 182.3)	4,543,829
Customer payments related to construction projects	953,775
Total Other Debit or Credit Items	$ 5,784,863

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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 (5.63%)			
2	Common Stock, $100 par value, 5,630 shares			
3	700 shares	11/18/52		70,000
4	700 shares	01/08/53		70,000
5	700 shares	02/25/53		70,000
6	700 shares	04/10/53		70,000
7	700 shares	05/12/53		70,000
8	1400 shares	07/27/53		140,000
9	730 shares	03/04/05		104,286
10				
11				
12				
13				
14				
15				
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18				
19				
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21				
22				
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40				
41				
42	Total Cost of Account 123.1 $ 594,286		TOTAL	594,286

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
	56,300			1
				2
		70,000		3
		70,000		4
		70,000		5
		70,000		6
		70,000		7
		140,000		8
		104,286		9
				10
				11
				12
				13
				14
				15
				16
				17
				18
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				41
	56,300	594,286		42

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 224 Line No.: 1 Column: a

See Note 1 of Notes to Financial Statements under Cost Method Investment for a full description of the OVEC investment.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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)	61,099,619	64,191,758	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)	29,469,912	30,487,901	Electric
8	Transmission Plant (Estimated)	1,057,366	2,312,678	Electric
9	Distribution Plant (Estimated)	2,200,332	3,016,166	Electric, Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	32,727,610	35,816,745	
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)	5,860,024	6,186,832	Various
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	99,687,253	106,195,335	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 227 Line No.: 9 Column: b

	Balance End of Year
Electric	$ 1,989,270
Gas	211,062
Total Distribution	$ 2,200,332

Schedule Page: 227 Line No.: 9 Column: c

	Balance End of Year
Electric	$ 2,499,740
Gas	516,426
Total Distribution	$ 3,016,166

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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		2014	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	93,940.00	891	62,379.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	62,379.00			
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	78,232.00	444		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	78,087.00	447	62,379.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	901.00		901.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	901.00			
40	Balance-End of Year			901.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	901.00	244		
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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.

2015		2016		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
62,379.00		62,379.00		1,621,854.00		1,902,931.00	891	1
								2
								3
						62,379.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						78,232.00	444	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
62,379.00		62,379.00		1,621,854.00		1,887,078.00	447	29
								30
								31
								32
								33
								34
								35
901.00		901.00		44,149.00		47,753.00		36
								37
								38
				901.00		1,802.00		39
901.00		901.00		43,248.00		45,951.00		40
								41
								42
								43
				901.00	38	1,802.00	282	44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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)	2014 No. (d)	2014 Amt. (e)
1	Balance-Beginning of Year	946.00	880		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	20,345.00		20,345.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:	3,846.00	157,170		
9					
10					
11					
12					
13					
14					
15	Total	3,846.00	157,170		
16					
17	Relinquished During Year:				
18	Charges to Account 509	23,548.00	116,234		
19	Other:				
20	Charges to Account 549	85.00	68		
21	Cost of Sales/Transfers:				
22	Adjustments		456		
23					
24					
25					
26					
27					
28	Total		456		
29	Balance-End of Year	1,504.00	41,292	20,345.00	
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
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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.

2015		2016		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						946.00	880	1
								2
								3
						40,690.00		4
								5
								6
								7
						3,846.00	157,170	8
								9
								10
								11
								12
								13
								14
						3,846.00	157,170	15
								16
								17
						23,548.00	116,234	18
								19
						85.00	68	20
								21
							456	22
								23
								24
								25
								26
								27
							456	28
						21,849.00	41,292	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
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								43
								44
								45
								46

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	231,705,649	23,775,059	184	91,392,827	164,087,881
2	Long-Term Interest Rate Swap	58,605,484	9,315,823	244/245	32,008,386	35,912,921
3	Winter Storm 2009 - Electric (Aug-10 to Jul-20)	33,116,949		571/593	4,367,070	28,749,879
4	Winter Storm 2009 - Gas (Aug-10 to Jul-20)	127,165		880	16,769	110,396
5	Asset Retirement Obligation - Electric	13,010,367	6,705,785	230/407.4	1,685,805	18,030,347
6	Asset Retirement Obligation - Gas	1,998,031	1,903,745	230/407.4	996,849	2,904,927
7	Asset Retirement Obligation - Common	17,227	8,277	230/407.4	506	24,998
8	Wind Storm 2008 (Aug-10 to Jul-20)	17,851,419		593	2,354,033	15,497,386
9	ASC 740 - Income Taxes	14,322,583	166,627	282/283	431,860	14,057,350
10	Swap Termination (Aug-10 to Apr-35)	8,678,746		930.2	388,660	8,290,086
11	Gas Supply Clause	5,439,239	11,936,838	803/254	10,016,432	7,359,645
12	Summer Storm 2011 (Jan-13 to Dec-17)	8,052,125		593	1,610,425	6,441,700
13	DSM Cost Recovery - Under-recovery	930,885	7,491,371	440-445	4,818,123	3,604,133
14	Unamortized Debt Expense (Aug-10 to Apr-35)	3,294,619		181	186,562	3,108,057
15	Performance-Based Rates	5,639,885	1,556,141	803	4,621,995	2,574,031
16	Environmental Cost Recovery	631,535	2,318,727	440-445	789,551	2,160,711
17	Fuel Adjustment Clause	6,068,000	9,635,000	440-445	14,011,000	1,692,000
18	2012 Rate Case Expense-Electric (Jan-13 to Dec-15)	894,413	26,576	928	324,638	596,351
19	2012 Rate Case Expense-Gas (Jan-13 to Dec-15)	284,806	8,475	928	103,386	189,895
20	2009 Rate Case Expense-Electric (Aug-10 to Jul-13)	163,236		928	163,236	
21	2009 Rate Case Expense-Gas (Aug-10 to Jul-13)	93,416		928	93,416	
22	Coal Contracts (Nov-10 to Dec-15)	1,671,497		253	925,578	745,919
23	Carbon Mgmt Research Group (Aug-10 to Jul-20)	154,470	199,620	930.2	219,180	134,910
24	KY Consortium for Carbon Storage (Aug-10 to Jul-14)	347,557		930.2/146	219,510	128,047
25	2011 General Mgmt Audit-Electric (Jan-13 to Dec-15)	91,583		928	30,528	61,055
26	2011 General Mgmt Audit-Gas (Jan-13 to Dec-15)	29,825		928	9,943	19,882
27	EKPC FERC Transmission Cost (Mar-09 to Feb-14)	197,834		456/566	169,572	28,262
28	MISO Exit Fee	9,798		440-445	9,798	
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44	TOTAL	413,428,343	75,048,064		171,965,638	316,510,769

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 9 Column: a

The regulatory assets represent the future revenue impact from the reversal of deferred income tax liability required for a tax depreciation basis adjustment.

Schedule Page: 232 Line No.: 14 Column: f

Unamortized Debt Expense (Aug-10 to Apr-35) Without Purchase Accounting	$ -
Purchase Accounting Adjustment	3,108,057
Total for Unamortized Debt Expense (Aug-10 to Apr-35)	$ 3,108,057

Schedule Page: 232 Line No.: 22 Column: f

Coal Contracts (Nov-10 to Dec-15) Without Purchase Accounting	$ -
Purchase Accounting Adjustment	745,919
Total for Coal Contracts (Nov-10 to Dec-15)	$ 745,919

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Goodwill	389,157,352				389,157,352
2						
3	OVEC Power Purchase Contract					
4	(Nov-10 to Mar-26)	74,923,412		254	5,540,496	69,382,916
5						
6	Coal Contracts					
7	(Nov-10 to Dec-16)	61,371,353		254	18,657,374	42,713,979
8						
9	Valuation of SO2 allowances					
10	(Nov-10 to Dec-40)	1,763,404		254	221,045	1,542,359
11						
12	Customer Credit Accounts					
13	Receivable	254,531	348,073			602,604
14						
15	Financing Expense	836	225,971			226,807
16						
17				107/108/		
18	Cellular Antenna Billable Chgs	119,450	502,495	143	519,012	102,933
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	527,590,338				503,728,950

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2013/Q4

FOOTNOTE DATA

Schedule Page: 233 Line No.: 1 Column: f

Goowill is the value attributed to KU's franchise as a result of PPL’s acquisition of LKE in November 2010.

Schedule Page: 233 Line No.: 4 Column: f

The balance of $69,382,916 relates to the fair value measurement of $86,856,705 for the power purchase contract between LG&E and OVEC that was recognized as a result of the acquisition by PPL in November 2010. The variance is 38 months of amortization in 2010, 2011, 2012 and 2013.

Schedule Page: 233 Line No.: 7 Column: f

The balance of $42,713,979 relates to the fair value measurement of $123,813,249 for LG&E's coal contracts that was recognized as a result of the acquisition by PPL in November 2010. The variance is 38 months of amortization in 2010, 2011, 2012 and 2013.

Schedule Page: 233 Line No.: 10 Column: f

The balance of $1,542,359 relates to the fair value measurement of $3,219,107 for LG&E's SO2 emission allowances that was recognized as a result of the acquisition by PPL in November 2010. The variance is 38 months of amortization in 2010, 2011, 2012 and 2013.

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Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Pensions	13,491,364	1,595,888
3	Other Post Retirement & Employment Benefits	18,075,925	17,887,870
4	Regulatory Tax Adjustments	30,527,885	28,692,664
5	Interest Rate Swaps		24,512,343
6	Asset Retirement Obligation	16,948,451	23,469,263
7	Other - See Notes for Detail	60,368,150	53,711,679
8	TOTAL Electric (Enter Total of lines 2 thru 7)	139,411,775	149,869,707
9	Gas		
10	Pensions	5,202,964	1,649,770
11	Other Post Retirement & Employment Benefits	5,066,177	5,010,004
12	Regulatory Tax Adjustments	1,378,393	1,358,429
13	Interest Rate Swaps		6,127,989
14	Asset Retirement Obligation	9,160,284	8,505,065
15	Other - See Notes for Detail	3,068,557	2,046,543
16	TOTAL Gas (Enter Total of lines 10 thru 15	23,876,375	24,697,800
17	Other (Specify)	218,810	236,990
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	163,506,960	174,804,497

Notes

	Electric Amounts		Gas Amounts	
	Beg. Bal.	End. Bal.	Beg. Bal.	End. Bal.
Vacation Pay	$ 1,613,350	$ 1,438,279	$ 494,223	$ 450,455
Workers' Compensation	1,228,731	981,957	365,620	303,927
Contingent Liability	901,151	653,774	-	-
Net Operating Loss Carryforward - Federal	-	3,498,598	-	-
Bad Debts Reserve	337,122	524,834	136,690	186,588
Demand Side Management	(2,552)	(154,220)	2,552	(1,247,787)
Capitalized Gas Inventory	-	-	1,801,646	2,483,264
Other	102,784	2,821,069	(204,764)	11,519
Total Line No. 7/15 Without Purchase Accounting	4,180,586	9,764,291	2,595,967	2,187,966
Purchase Accounting Adjustments	56,187,564	43,947,388	472,590	(141,423)
Total Line No. 7/15 With Purchase Accounting	$60,368,150	$53,711,679	$3,068,557	$2,046,543

	Other Amounts	
	Beginning	Ending
Non-Qualified Thrift	$ 218,810	$ 236,990
Line 17	$ 218,810	$ 236,990

Balance Beginning of Year	$163,506,960
Less Debits to	
Account 410.1	50,859,639
Account 410.2	982
Plus Credits to	
Account 411.1	40,580,889
Account 411.2	19,162
Other Balance Sheet Accounts	21,558,107
Balance at End of Year	$174,804,497

Note: Some beginning balance amounts were reclassified from prior years' Form 1 ending balance amounts for

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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.

presentation purposes. The total beginning balance deferrals did not change.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock			
2	Common Stock, Without Par Value	75,000,000		
3	Total Common	75,000,000		
4				
5	Preferred Stock			
6	Preferred Stock, $25 Par Value	1,720,000		
7	Preferred Stock, Without Par Value	6,750,000		
8	Total Preferred	8,470,000		
9				
10				
11	Note:			
12	There is no call price for common stock,			
13	without par value.			
14				
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16	The common stock of LG&E is owned by its			
17	parent company, LKE.			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
21,294,223	425,170,424					2
21,294,223	425,170,424					3
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 250 Line No.: 8 Column: a

No shares of preferred stock remain issued or outstanding.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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, 2013	1,277,667,368
3	Contributed Capital March 31, 2013	25,000,000
4	Contributed Capital June 30, 2013	29,000,000
5	Contributed Capital December 31, 2013	32,000,000
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40	TOTAL	1,363,667,368

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 253   Line No.: 1   Column: a

See footnote data detail on Schedule Page: 112, Line No.: 7, Column: c.

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Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Expenses on Common Stock	835,889
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22	TOTAL	835,889

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	Louisville Metro 2000 Series A, due 05/01/2027, Variable	25,000,000	883,831
4	Trimble County 2000 Series A, due 08/01/2030, Variable	83,335,000	1,154,826
5	Jefferson County 2001 Series A., due 09/01/2027, Variable	10,104,000	526,085
6	Jefferson County 2001 Series A, due 09/01/2026, Variable	22,500,000	242,653
7	Trimble County 2001 Series A, due 09/01/2026, Variable	27,500,000	263,855
8	Jefferson County 2001 Series B, due 11/01/2027, Variable	35,000,000	281,244
9	Trimble County 2001 Series B, due 11/01/2027, Variable	35,000,000	281,283
10	Trimble County 2002 Series A, due 10/01/2032, Variable	41,665,000	1,112,006
11	Louisville Metro 2003 Series A, due 10/01/2033, 1.650%	128,000,000	4,792,737
12	Louisville Metro 2005 Series A, due 02/01/2035, 2.200%	40,000,000	1,428,142
13	Trimble County 2007 Series A, due 06/01/2033, 4.600%	60,000,000	1,239,280
14	Louisville Metro 2007 Series A, due 06/01/2033, 1.150%	31,000,000	938,023
15	Louisville Metro 2007 Series B, due 06/01/2033, 1.600%	35,200,000	1,085,694
16	Interest Rate Swaps:		
17			
18	First Mortgage Bonds:		
19	2010 due 11/15/2015, 1.625%	250,000,000	2,563,689
20			882,500 D
21	2010 due 11/15/2040, 5.125%	285,000,000	3,570,026
22			3,100,600 D
23	2013 due 11/15/2043, 4.650% (Case No. 2012-00233 August 3, 2012)	250,000,000	2,611,393
24			1,800,000 D
25	TOTAL ACCOUNT 221	1,359,304,000	28,757,867
26			
27	ACCOUNT 222:		
28			
29			
30			
31	TOTAL ACCOUNT 222		
32			
33	TOTAL	1,365,880,717	28,757,867

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
05/19/2000	05/01/2027	05/19/2000	05/01/2027	25,000,000	199,817	3
08/09/2000	08/01/2030	08/09/2000	08/01/2030	83,335,000	120,604	4
09/11/2001	09/01/2027	09/11/2001	09/01/2027	10,104,000	13,859	5
03/06/2002	09/01/2026	03/06/2002	09/01/2026	22,500,000	52,995	6
03/06/2002	09/01/2026	03/06/2002	09/01/2026	27,500,000	62,333	7
03/22/2002	11/01/2027	03/22/2002	11/01/2027	35,000,000	125,390	8
03/22/2002	11/01/2027	03/22/2002	11/01/2027	35,000,000	124,437	9
10/23/2002	10/01/2032	10/23/2002	10/01/2032	41,665,000	70,271	10
11/20/2003	10/01/2033	11/20/2003	10/01/2033	128,000,000	2,112,000	11
04/13/2005	02/01/2035	04/13/2005	02/01/2035	40,000,000	2,183,167	12
04/26/2007	06/01/2033	04/26/2007	06/01/2033	60,000,000	2,760,000	13
04/26/2007	06/01/2033	04/26/2007	06/01/2033	31,000,000	248,603	14
04/26/2007	06/01/2033	04/26/2007	06/01/2033	35,200,000	563,200	15
					7,895,241	16
						17
						18
11/16/2010	11/15/2015	11/16/2010	11/15/2015	250,000,000	4,062,500	19
		11/16/2010	11/15/2015			20
11/16/2010	11/15/2040	11/16/2010	11/15/2040	285,000,000	14,606,250	21
		11/16/2010	11/15/2040			22
11/14/2013	11/15/2043	11/14/2013	11/15/2043	250,000,000	1,311,449	23
			11/15/2043			24
				1,359,304,000	36,512,116	25
						26
						27
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						29
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				1,357,530,563	28,812,421	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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 223:		
2	TOTAL ACCOUNT 223		
3			
4	ACCOUNT 224:		
5	Purchase Accounting Adjustments for Fair Value Measurement		
6	Louisville Metro 2007 Series A, due 06/01/2033, 1.150%	2,702,070	
7	Trimble County 2007 Series A, due 06/01/2033, 4.600%	-2,062,667	
8	Jefferson County 2000 Series A, due 05/01/2027, Variable	1,397,125	
9	Louisville Metro 2005 Series A, due 02/01/2035, 2.200%	4,540,189	
10	TOTAL ACCOUNT 224	6,576,717	
11			
12			
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31			
32			
33	TOTAL	1,365,880,717	28,757,867

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
						3
						4
						5
		11/01/2010	06/01/2017		-2,442,831	6
		11/01/2010	06/01/2033	-1,773,437	91,336	7
		11/01/2010	12/01/2016		-1,213,664	8
		11/01/2010	08/01/2019		-4,134,536	9
				-1,773,437	-7,699,695	10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
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						32
				1,357,530,563	28,812,421	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/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 premiums 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 LG&E, issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates LG&E to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds.

Schedule Page: 256 Line No.: 16 Column: a

As of December 31, 2013, the company had in effect four interest-rate swap agreements to hedge its exposure to tax exempt rates related to Pollution Control Bonds, Variable Rate Series. The Company’s position under the swap agreements are to pay a fixed rate and receive a variable rate based on the Securities Industry and Financial Markets Association Index or London Interbank Offered Rate (LIBOR). The specifics for each swap agreement related to notional amounts, maturity dates, payable and receivable positions are as follows:

Notional Amount	Maturity	Payable	Receivable
$83,335,000	11/01/2020	Fixed 5.495%	SIFMA Index
$32,000,000	10/01/2033	Fixed 3.657%	68% of 1 mo LIBOR
$32,000,000	10/01/2033	Fixed 3.645%	68% of 1 mo LIBOR
$32,000,000	10/01/2033	Fixed 3.695%	68% of 1 mo LIBOR

By Order in Case No. 2012-00233, LG&E was authorized by the KPSC to enter into hedging agreements to lock in interest rates for debt that was issued in November 2013. In October 2012, LG&E entered into $150 million of forward-starting swaps using PPL as a pass through entity for all hedging agreements. In April 2013, LG&E added an additional $100 million of forward-starting swaps with PPL. In September 2013 when the initial swaps settled, LG&E entered into $250 million of forward-starting swaps with PPL during the interim period until the debt was issued. The settled swaps netted a gain of $43 million recorded as a regulatory liability at December 31, 2013. The regulatory liability is being amortized over the life of the debt to which it relates.

Schedule Page: 256 Line No.: 18 Column: a

Proceeds from LG&E’s First Mortgage Bonds issued in 2010 were used to repay the loans from a PPL subsidiary and for general corporate purposes. Proceeds from LG&E's First Mortgage Bonds issued in 2013 were used for capital expenditures and general corporate purposes. The first mortgage bonds were issued at a discount.

In April 2011, LG&E filed 2011 Registration Statements with the SEC related to offers to exchange securities issued in November 2010 in transactions not registered under the Securities Act of 1933 with similar but registered securities. The 2011 Registration Statements became effective in June 2011 and the exchanges were completed in July 2011, with substantially all securities being exchanged.

As of December 31, 2013, 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: 256.1 Line No.: 1 Column: a

LG&E did not have long-term notes with associated companies in 2013.

Schedule Page: 256.1 Line No.: 4 Column: a

Upon completion of the acquisition by PPL, push-down accounting was used, resulting in adjustments to certain of the Company’s assets and liabilities to reflect their estimated fair values on the acquisition date.

The following pollution control bonds with coupon rates listed below were fair valued as a

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FOOTNOTE DATA

result of the PPL acquisition:

Bond Issue	(221) Principal	(224) Fair Value Adjustment	Total Purchase Accounting
Louisville Metro 2007 Series A, due 6/1/2033, 1.15%	$31,000,000	$2,702,070	$33,702,070
Trimble County 2007 Series A, due 6/1/2033, 4.600%	$60,000,000	($2,062,667)	$57,937,333
Jefferson County 2000 Series A, due 5/1/2027, Var	$25,000,000	$1,397,125	$26,397,125
Louisville Metro 2005 Series A, due 2/1/2035, 2.20%	$40,000,000	$4,540,189	$44,540,189

The purchase accounting adjustments were recorded to Other Long-Term Debt Account (224). At December 31, 2013, all fair market value adjustments, with the exception of Trimble County 2007 Series A, were written off due to mandatory puts on the bonds. Amortization is recorded to Interest on Long-Term Debt Account (427).

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Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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)	163,405,117
2		
3		
4	Taxable Income Not Reported on Books	
5	See footnote	53,490,193
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See footnote	128,886,971
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See footnote	3,629,518
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See footnote	171,828,767
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	170,323,996
28	Show Computation of Tax:	
29		
30	Federal Tax Net Income	170,323,996
31	35% Rounded	59,613,399
32	Add: Adjustment of Prior Years' Taxes & Other	-7,761,018
33		
34	Total:	51,852,381
35		
36		
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43		
44		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 5 Column: b

Contribution in Aid of Construction	$ 5,159,429
Interest Rate Swaps	42,854,000
Purchased Gas Adjustment	1,100,764
Fuel Adjustment Clause KY	4,376,000
Total	$ 53,490,193

Schedule Page: 261 Line No.: 10 Column: b

Federal Income Taxes:	
Utility Operating Income	$ 53,107,974
Other Income and Deductions	(1,255,593)
Provision for Deferred Income Taxes	28,249,076
Pensions	8,403,122
Capitalized Interest	15,276,411
Loss on Reacquired Debt, Net of Amortization	1,525,396
Gas Line Tracker	5,797,265
Storm Damages	8,348,297
Prepaid Insurance	1,824,986
Current State Income Taxes	3,794,160
Nondeductible Expenses	936,400
Bad Debt Reserves	610,823
Regulatory Expenses	649,626
Deferred Rent Payable	647,695
Other	971,333
Total	$128,886,971

Schedule Page: 261 Line No.: 15 Column: b

Amortization of Investment Tax Credit	$ 2,100,342
Environmental Cost Recovery	1,529,176
Total	$ 3,629,518

Schedule Page: 261 Line No.: 20 Column: b

Tax over Book Depreciation, Net and Repairs	$126,858,110
Cost of Removal	19,472,540
Demand Side Management	2,673,248
Regulatory Liability on AROs	2,432,833
IRC 199 Manufacturing Deduction	7,324,368
Contribution Carryforward	1,820,473
Contingency Reserve	887,595
Vacation Pay	432,369
Workers' Compensation	792,975
Post Retirement Benefits	674,798
ASC 740-10 State Current Taxes	584,609
Other	175,154
Total Without Purchase Accounting	164,129,072
Purchase Accounting Adjustments - FMV Bonds	7,699,695
Total	$171,828,767

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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 Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Federal:					
2	Income			46,900,895	38,692,155	
3	FICA	640,795		7,002,681	6,917,126	
4						
5	Kentucky and Other States:					
6	Income			13,295,648	12,515,455	
7	Public Service Commission		1,116,345	2,274,456	2,316,221	
8	Use (Kentucky)	-289,777		5,999,416	4,540,762	
9	Use (Indiana)			101,053	101,053	
10	Vehicle License					
11						
12	Federal & Kentucky:					
13	Unemployment Insurance	126,184		228,936	186,886	
14						
15	Local:					
16	Occupational					
17						
18	Kentucky & Indiana:					
19	Property Taxes	1,258,293		21,412,048	22,248,069	
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
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35						
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37						
38						
39						
40						
41	TOTAL	1,735,495	1,116,345	97,215,133	87,517,727	

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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
8,208,740		41,181,745			5,719,150	2
726,350		6,874,749			127,932	3
						4
						5
780,193		13,122,319			173,329	6
	1,158,110	1,790,451			484,005	7
1,168,877					5,999,416	8
					101,053	9
						10
						11
						12
168,234		292,030			-63,094	13
						14
						15
		34,543			-34,543	16
						17
						18
422,272		16,040,130			5,371,918	19
						20
						21
						22
						23
						24
						25
						26
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						31
						32
						33
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						38
						39
						40
11,474,666	1,158,110	79,335,967			17,879,166	41

BLANK

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 1 Column: a

Segregation of Other	Column Other (l)	Page 115 Gas Acct. 408.1 - 409.1	Page 117 Other Inc & Deductions 408.2 – 409.2	Other Accounts
Federal:				
Income	$ 5,719,150	$11,926,229	$(1,255,593)	$(4,951,486)
FICA	127,932	1,598,642	-	(1,470,710)
Kentucky & Other States:				
Income	173,329	2,955,930	(192,086)	(2,590,515)
PSC	484,005	484,005	-	-
6% Use (Kentucky)	5,999,416	-	-	5,999,416
7% Use (Indiana)	101,053	-	-	101,053
Vehicle License	-	-	-	-
Federal & Kentucky:				
Unemployment Ins	(63,094)	66,862	-	(129,956)
Local:				
Occupational	(34,543)	8,635	-	(43,178)
Kentucky & Indiana:				
Property Taxes	5,371,918	5,327,001	5,960	38,957
Total	$17,879,166	$22,367,304	$(1,441,719)	$(3,046,419)

Reconciliation to Schedule Page: 114-115,
Line No.: 14-16:

Federal Income:		State Income:		Other:	
Electric	$41,181,745	Electric	$13,122,319	Elec Total	$79,335,967
Gas	11,926,229	Gas	2,955,930	Gas Total	22,367,304
Total	$53,107,974	Total	$16,078,249	Less Federal	(53,107,974)
				Less State	(16,078,249)
				Total	$32,517,048

Schedule Page: 262 Line No.: 2 Column: b

Balance at Beginning of Year totaling $4,951,486 was reclassified to Accounts Receivable (143).

Schedule Page: 262 Line No.: 6 Column: b

Balance at Beginning of Year totaling $3,175,124 was reclassified to Accounts Receivable (143).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6	Various	17,104,280			411.4	1,730,555	
7	15%	22,336,362			411.4	256,567	
8	TOTAL	39,440,642				1,987,122	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16	Gas Utility	430,585			411.4	113,220	
17	TOTAL	430,585				113,220	
18							
19							
20							
21							
22							
23							
24							
25							
26							
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41							
42							
43							
44							
45							
46							
47		39,871,227				2,100,342	
48	Grand Total	39,871,227				2,100,342	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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
15,373,725	32 Years		6
22,079,795	54 Years		7
37,453,520			8
			9
			10
			11
			12
			13
			14
			15
317,365	33 Years		16
317,365			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
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			36
			37
			38
			39
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			46
37,770,885			47
37,770,885			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	Contract Retention	1,973,934			10,507,280	12,481,214
2						
3	Brown CT Long-Term Service					
4	Agreement	3,317,573	107/232	826,224		2,491,349
5						
6	Corporate Headquarters Lease					
7	(Jul-12 to Dec-25)	346,322			647,695	994,017
8						
9	Valuation of Coal Contracts					
10	(Nov-10 to Dec-15)	1,671,497	182.3	925,578		745,919
11						
12	Deferred Compensation	562,493			46,738	609,231
13						
14	Prepaid Transmission System Fee:					
15	MCI Telecom	558,076	454	36,796		521,280
16						
17	Clearing Accounts Transferred					
18	from Other Deferred Debits	20,545	184	5,051,175	5,051,175	20,545
19						
20	Uncertain Tax Position - State	584,609	236	584,609		
21						
22	Unearned Revenue					
23	Pole Attachments	45,764	454	45,764		
24						
25						
26						
27						
28						
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45						
46						
47	TOTAL	9,080,813		7,470,146	16,252,888	17,863,555

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2013/Q4

FOOTNOTE DATA

Schedule Page: 269 Line No.: 1 Column: a

Retainage is accrued on an invoice basis and will continue to increase throughout a project's life until completion.

Schedule Page: 269 Line No.: 10 Column: f

The balance of $745,919 relates to the fair value measurement of $11,262,929 for LG&E's coal contracts that was recognized as a result of the acquisition by PPL in November 2010. The variance is 38 months of amortization in 2010, 2011, 2012 and 2013.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	419,898,751	110,025,178	61,101,760
3	Gas	115,971,222	30,264,713	16,815,221
4				
5	TOTAL (Enter Total of lines 2 thru 4)	535,869,973	140,289,891	77,916,981
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	535,869,973	140,289,891	77,916,981
10	Classification of TOTAL			
11	Federal Income Tax	468,153,837	124,635,892	66,759,102
12	State Income Tax	67,716,136	15,653,999	11,157,879
13	Local Income Tax			

NOTES

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
		254	400,702	254	1,135,049	469,556,516	2
		254	334,935	254	253,072	129,338,851	3
							4
			735,637		1,388,121	598,895,367	5
							6
							7
							8
			735,637		1,388,121	598,895,367	9
							10
			585,374		814,113	526,259,366	11
			150,263		574,008	72,636,001	12
							13

NOTES (Continued)

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/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, 2012, is $11,782,446.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2012, is $(240,815).

Schedule Page: 274 Line No.: 2 Column: k

The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2013, is $16,448,359.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2013, is $(975,162).

Schedule Page: 274 Line No.: 3 Column: b

The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2012, is $7,534,948.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2012, is $1,734,448.

Schedule Page: 274 Line No.: 3 Column: k

The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2013, is $7,372,423.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2013, is $1,816,311.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent’s accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Loss on Reacquired Debt	7,107,090	287,267	785,112
4	Storm Damages	23,024,201	4,436,206	7,742,402
5	FAC Under Recovery	2,360,453	2,383,854	4,086,118
6	Asset Retirement Obligation	5,065,925	2,060,517	105,539
7	Pension - Regulatory Asset	52,821,849	5,676,043	20,088,506
8	Other	64,732,515	2,020,358	19,996,508
9	TOTAL Electric (Total of lines 3 thru 8)	155,112,033	16,864,245	52,804,185
10	Gas			
11	Loss on Reacquired Debt	660,479	55,125	150,659
12	Storm Damages	-15,764	76,333	17,624
13	Asset Retirement Obligation	779,043	396,495	42,896
14	Purchased Gas	3,006,224	786,278	1,214,474
15	Pension - Regulatory Asset	15,777,955	1,695,441	6,000,463
16	Other	370,558	228,498	4,461,128
17	TOTAL Gas (Total of lines 11 thru 16)	20,578,495	3,238,170	11,887,244
18	Other	-204,610		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	175,485,918	20,102,415	64,691,429
20	Classification of TOTAL			
21	Federal Income Tax	148,387,122	17,639,030	55,350,564
22	State Income Tax	27,098,796	2,463,385	9,340,865
23	Local Income Tax			

NOTES

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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
						6,609,245	3
						19,718,005	4
						658,189	5
						7,020,903	6
						38,409,386	7
		182/190	1,141,898	182/190	19,892,584	65,507,051	8
			1,141,898		19,892,584	137,922,779	9
							10
						564,945	11
						42,945	12
						1,132,642	13
						2,578,028	14
						11,472,933	15
		190	246,139	190	4,805,568	697,357	16
			246,139		4,805,568	16,488,850	17
204,613	3						18
204,613	3		1,388,037		24,698,152	154,411,629	19
							20
204,613	3		1,369,986		21,084,713	130,594,925	21
			18,051		3,613,439	23,816,704	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 8 Column: b

The balance in Accumulated Deferred Income Taxes - Other (283) was adjusted due to the purchase of LG&E by PPL Corporation in November 2010. The following reflects the balance at December 31, 2012:

Prepaid Insurance	$ 1,325,930
Management Audit Fees	35,626
MISO Exit Fees	(343,511)
Rate Case Expenses	411,424
Regulatory Tax Adjustments	5,571,485
Swap Termination	3,376,031
Other	690
Accumulated Deferred Income Taxes - Other (283) Without Purchase Accounting	10,377,675
Purchase Accounting Adjustments	54,354,840
Total for Accumulated Deferred Income Taxes- Other (283)	$64,732,515

Schedule Page: 276 Line No.: 8 Column: c

The balance was adjusted due to the amortization of purchase accounting adjustments that arose from the purchase of LG&E by PPL in November 2010. The following reflects the activity during the year charged to 410.1:

Debit Change Account 410.1:

Prepaid Insurance	$ 31,043
Management Audit Fees	641
Rate Case Expenses	35,108
Swap Termination	948,737
Interest Rate Swap - Regulatory Asset	381,235
Other	91,359
Total Without Purchase Accounting	1,488,123
Purchase Accounting Adjustment	532,235
Total	$ 2,020,358

Schedule Page: 276 Line No.: 8 Column: d

The balance was adjusted due to the amortization of purchase accounting adjustments that arose from the purchase of LG&E by PPL in November 2010. The following reflects the activity during the year charged to 411.1:

Credit Change Account 411.1:

Prepaid Insurance	$ 606,077
Management Audit Fees	12,517
Rate Case Expenses	214,554
Swap Termination	1,099,925
Interest Rate Swap - Regulatory Asset	7,443,161
Other	229,031
Total Without Purchase Accounting	9,605,265
Purchase Accounting Adjustment	10,391,243
Total	$19,996,508

Schedule Page: 276 Line No.: 8 Column: h

MISO Exit Fees	$ 18,545
Regulatory Tax Adjustments	124,079
Interest Rate Swap - Regulatory Asset	984,576

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FOOTNOTE DATA

Other	14,698

Total	$ 1,141,898

Schedule Page: 276 Line No.: 8 Column: j

MISO Exit Fees	$ 362,056
Regulatory Tax Adjustments	20,903
Interest Rate Swap - Regulatory Asset	19,222,681
Other	286,944

Total	$19,892,584

Schedule Page: 276 Line No.: 8 Column: k

The balance in Accumulated Deferred Income Taxes - Other (283) was adjusted due to the purchase of LG&E by PPL Corporation in November 2010. The following reflects the balance at December 31, 2013:

Prepaid Insurance	$ 750,896
Management Audit Fees	23,750
Rate Case Expenses	231,978
Regulatory Tax Adjustments	5,468,309
Swap Termination	3,224,843
Interest Rate Swap - Regulatory Asset	11,176,179
Other	135,264

Accumulated Deferred Income Taxes - Other (283) Without Purchase Accounting	21,011,219
Purchase Accounting Adjustments	44,495,832

Total for Accumulated Deferred Income Taxes - Other (283)	$65,507,051

Schedule Page: 276 Line No.: 16 Column: b

Prepaid Insurance	$ 311,024
Management Audit Fees	11,601
Rate Case Expenses	147,128
Gas Line Tracker - Regulatory Asset	(99,195)

Total for Accumulated Deferred Income Taxes - Other (283)	$ 370,558

Schedule Page: 276 Line No.: 16 Column: c

Debit Change Account 410.1:

Prepaid Insurance	$ 7,282
Management Audit Fees	209
Rate Case Expenses	3,955
Gas Line Tracker - Regulatory Asset	121,743
Interest Rate Swap - Regulatory Asset	95,309

Total	$ 228,498

Schedule Page: 276 Line No.: 16 Column: d

Credit Change Account 411.1:

Prepaid Insurance	$ 142,169
Management Audit Fees	4,075
Rate Case Expenses	77,214
Gas Line Tracker - Regulatory Asset	2,376,879
Interest Rate Swap - Regulatory Asset	1,860,791

Total	$ 4,461,128

Schedule Page: 276 Line No.: 16 Column: h

Interest Rate Swap - Regulatory Asset	$ 246,139

Schedule Page: 276 Line No.: 16 Column: j

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FOOTNOTE DATA

Interest Rate Swap - Regulatory Asset	$ 4,805,568

Schedule Page: 276 Line No.: 16 Column: k

Prepaid Insurance	$ 176,137
Management Audit Fees	7,735
Rate Case Expenses	73,869
Gas Line Tracker - Regulatory Asset	(2,354,331)
Interest Rate Swap - Regulatory Asset	2,793,947

Total for Accumulated Deferred Income Taxes - Other (283)	$ 697,357

Schedule Page: 276 Line No.: 18 Column: b

ASC 740-10 State Tax Current	$ (204,610)

Schedule Page: 276 Line No.: 18 Column: e

ASC 740-10 State Tax Current	$ 204,613

Schedule Page: 276 Line No.: 18 Column: f

ASC 740-10 State Tax Current	$ 3

Schedule Page: 276 Line No.: 18 Column: k

ASC 740-10 State Tax Current	$ -

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	OVEC Power Purchase Contract (Nov-10 to Mar-26)	74,923,412	186	5,540,496		69,382,916
2	LT Interest Rate Swap Non-LKE Affiliate	7,142,276	175	18,397,081	54,108,804	42,853,999
3	Coal Contracts (Nov-10 to Dec-16)	61,371,353	186	18,657,374		42,713,979
4	ASC 740 - Income Taxes	42,151,008	190/282	3,550,512	880,787	39,481,283
5	Gas Line Tracker	255,000	480-482	66,112	5,863,377	6,052,265
6	Gas Supply Clause	3,094,662	803	4,364,116	4,575,806	3,306,352
7	Emission Allowances (Nov-10 to Dec-40)	1,763,404	186	421,693	200,648	1,542,359
8	MISO Exit Fee Refund	892,859	143	305,545	282,955	870,269
9	Cost of Removal - Gas	2,175,558	108	2,196,578	21,020	
10	Cost of Removal - Electric	257,275	108	296,015	38,740	
11	Purchased Gas Adjustment	256,376	182.3/803	259,924	3,548	
12	Fuel Adjustment Clause		440-445	13,385,000	13,385,000	
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
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27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	194,283,183		67,440,446	79,360,685	206,203,422

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 278 Line No.: 1 Column: f

OVEC Power Purchase Contract (Nov-10 to Mar-26) Without Purchase Accounting	$ -
Purchase Accounting Adjustment	69,382,916
Total for Power Purchase Contract (Nov-10 to Mar-26)	$ 69,382,916

Schedule Page: 278 Line No.: 3 Column: f

Coal Contracts (Nov-10 to Dec-16) Without Purchase Accounting	$ -
Purchase Accounting Adjustment	42,713,979
Total for Coal Contracts (Nov-10 to Dec-16)	$ 42,713,979

Schedule Page: 278 Line No.: 4 Column: a

The regulatory liabilities represent the future revenue impact from the reversal of deferred income taxes required for unamortized investment tax credits and deferred taxes provided at rates in excess of currently enacted rates.

Schedule Page: 278 Line No.: 7 Column: f

Emission Allowances (Nov-10 to Dec-40) Without Purchase Accounting	$ -
Purchase Accounting Adjustment	1,542,359
Total for Emission Allowances (Nov-10 to Dec-40)	$ 1,542,359

Schedule Page: 278 Line No.: 9 Column: f

In August 2013, the accumulated cost of removal depreciation reserve balance associated with the underlying physical assets for which asset retirement obligations have been established was reclassed from Other Regulatory Liabilities (254) to the Accumulated Provision for Depreciation (108).

Schedule Page: 278 Line No.: 10 Column: f

In August 2013, the accumulated cost of removal depreciation reserve balance associated with the underlying physical assets for which asset retirement obligations have been established was reclassed from Other Regulatory Liabilities (254) to the Accumulated Provision for Depreciation (108).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	405,961,655	383,159,861
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	329,906,063	316,533,477
5	Large (or Ind.) (See Instr. 4)	174,274,392	164,431,527
6	(444) Public Street and Highway Lighting	2,884,918	2,817,941
7	(445) Other Sales to Public Authorities	88,714,502	90,196,246
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,001,741,530	957,139,052
11	(447) Sales for Resale	78,580,878	91,911,504
12	TOTAL Sales of Electricity	1,080,322,408	1,049,050,556
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	1,080,322,408	1,049,050,556
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,429,251	5,372,160
17	(451) Miscellaneous Service Revenues	1,663,165	1,528,305
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	3,392,282	3,566,589
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	1,345,107	1,451,015
22	(456.1) Revenues from Transmission of Electricity of Others	7,444,228	8,377,778
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	16,274,033	20,295,847
27	TOTAL Electric Operating Revenues	1,096,596,441	1,069,346,403

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
4,164,049	4,259,211	348,047	346,445	2
				3
3,685,169	3,733,684	42,062	41,858	4
2,699,966	2,666,220	429	411	5
18,441	21,157	650	631	6
1,131,350	1,157,457	4,124	4,093	7
				8
				9
11,698,975	11,837,729	395,312	393,438	10
2,779,341	3,632,775	13	14	11
14,478,316	15,470,504	395,325	393,452	12
				13
14,478,316	15,470,504	395,325	393,452	14

Line 12, column (b) includes $ 1,003,242 of unbilled revenues.
Line 12, column (d) includes 16,742 MWH relating to unbilled revenues

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 300 Line No.: 21 Column: b

Items which compose Other Electric Revenues (456) year-to-date activity:

2013 invoices to Kosmos	$ 934,467
Other items less than $250,000 each	410,640
Total Other Electric Revenues	$ 1,345,107

Schedule Page: 300 Line No.: 21 Column: c

Items which compose Other Electric Revenues (456) year-to-date activity:

2012 invoices to Kosmos	$ 1,133,043
Other items less than $250,000 each	317,972
Total Other Electric Revenues	$ 1,451,015

Schedule Page: 300 Line No.: 22 Column: b

Items which compose Revenues from Transmission of Electricity of Others (456.1) year-to-date activity:

2013 invoices to Owensboro Municipal Utilities	$ 2,139,002
2013 invoices to East Kentucky Power Cooperative	1,777,242
2013 invoices to Kentucky Municipal Power Agency	786,337
2013 invoices to City of Frankfort	638,746
2013 invoices to Cargill Power Markets, LLC	394,013
2013 invoices to City of Madisonville	259,407
Other items less than $250,000 each	1,449,481
Total Revenues from Transmission of Electricity of Others	$ 7,444,228

Schedule Page: 300 Line No.: 22 Column: c

Items which compose Revenues from Transmission of Electricity of Others (456.1) year-to-date activity:

2012 invoices to East Kentucky Power Cooperative	$ 2,466,391
2012 invoices to Owensboro Municipal Utilities	2,265,781
2012 invoices to Kentucky Municipal Power Agency	1,107,526
2012 invoices to City of Frankfort	579,593
2012 invoices to Ameren Energy Marketing Company	499,855
2012 invoices to City of Madisonville	265,532
Other items less than $250,000 each	1,193,100
Total Revenues from Transmission of Electricity of Others	$ 8,377,778

Schedule Page: 300 Line No.: 1 Column: $

This value contains unbilled revenue of $920,587 and accrued revenue of $82,655. The accrued revenue represents the following:

DSM Accrual	$ 2,929,479
ECR Accrual	1,529,176
FAC Accrual	(4,376,000)
Total Accrual	$ 82,655

Schedule Page: 300 Line No.: 1 Column: MWH

Unbilled revenue of 16,742 MWH represents the net change of unbilled MWH from the previous period; as a result, it could be positive or negative.

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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 440					
2	Residential Service (RS)	4,142,328	400,778,311	354,001	11,701	0.0968
3	Volunteer Fire Department (VFD)	402	35,131	2	201,000	0.0874
4	General Service (GS)	140	15,108	12	11,667	0.1079
5	Power Service (PS)					
6	Lighting Service (LS)	2,483	591,019	3,620	686	0.2380
7	Restricted Lighting Service (RLS)	2,825	533,605	2,893	976	0.1889
8	Low Emission Vehicle (LEV)	109	9,918	6	18,167	0.0910
9	Duplicate Customers			-12,487		
10						
11	Reclassifications and Adjustments		-26,040			
12						
13						
14						
15						
16						
17						
18						
19						
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22						
23						
24						
25						
26						
27						
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29						
30						
31						
32						
33						
34						
35						
36						
37	Subtotal	4,148,287	401,937,052	348,047	11,919	0.0969
38	Unbilled	15,762	4,024,603			0.2553
39	Total	4,164,049	405,961,655	348,047	11,964	0.0975
40						
41	TOTAL Billed	11,682,233	1,000,738,288	395,312	29,552	0.0857
42	Total Unbilled Rev.(See Instr. 6)	16,742	1,003,242	0	0	0.0599
43	TOTAL	11,698,975	1,001,741,530	395,312	29,594	0.0856

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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 (RS)	87	8,263	6	14,500	0.0950
3	General Service (GS)	1,273,000	133,366,331	41,856	30,414	0.1048
4	Power Service (PS)	2,045,646	167,957,407	2,588	790,435	0.0821
5	Time-of-Day Secondary (TODS)	663,475	50,121,458	192	3,455,599	0.0755
6	Ind Time-of-Day Prim. (ITODP)	1,517,210	97,727,194	57	26,617,719	0.0644
7	Com Time-of-Day Prim. (CTODP)	173,833	12,456,853	23	7,557,957	0.0717
8	Retail Transmission Service (RTS)	656,372	34,032,900	6	109,395,333	0.0519
9	Lighting Service (LS)	30,421	5,006,856	8,271	3,678	0.1646
10	Restricted Lighting Service (RLS)	16,517	3,718,667	4,047	4,081	0.2251
11	Lighting Energy Service (LE)	4	281	5	800	0.0703
12	General Responsive Pricing (GRP)					
13	Duplicate Customers			-14,560		
14						
15	Reclassifications and Adjustments		-2,799			
16						
17						
18						
19						
20						
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24						
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34						
35						
36						
37						
38	Subtotal	6,376,565	504,393,411	42,491	150,069	0.0791
39	Unbilled	8,570	-212,956			-0.0248
40	Total	6,385,135	504,180,455	42,491	150,270	0.0790
41	TOTAL Billed	11,682,233	1,000,738,288	395,312	29,552	0.0857
42	Total Unbilled Rev.(See Instr. 6)	16,742	1,003,242	0	0	0.0599
43	TOTAL	11,698,975	1,001,741,530	395,312	29,594	0.0856

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 444					
2	General Service (GS)	110	11,016	2	55,000	0.1001
3	Lighting Service (LS)	7,485	1,085,764	969	7,724	0.1451
4	Restricted Lighting Service (RLS)	7,120	1,409,962	1,013	7,029	0.1980
5	Lighting Energy Service (LE)	2,325	152,615	151	15,397	0.0656
6	Traffic Energy Service (TE)	2,133	199,017	823	2,592	0.0933
7	Duplicate Customers			-2,308		
8						
9	Reclassifications and Adjustments		-774			
10						
11						
12						
13						
14						
15						
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35						
36						
37						
38	Subtotal	19,173	2,857,600	650	29,497	0.1490
39	Unbilled	-732	27,318			-0.0373
40	Total	18,441	2,884,918	650	28,371	0.1564
41	TOTAL Billed	11,682,233	1,000,738,288	395,312	29,552	0.0857
42	Total Unbilled Rev.(See Instr. 6)	16,742	1,003,242	0	0	0.0599
43	TOTAL	11,698,975	1,001,741,530	395,312	29,594	0.0856

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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 (RS)	1,306	126,108	110	11,873	0.0966
3	General Service (GS)	114,691	11,551,903	2,272	50,480	0.1007
4	Power Service (PS)	320,226	28,409,882	316	1,013,373	0.0887
5	Time-of-Day Secondary (TODS)	56,892	4,552,438	18	3,160,667	0.0800
6	Ind Time-of-Day Primary (ITODP)	57,977	3,824,508	6	9,662,833	0.0660
7	Com Time-of-Day Primary (CTODP)	194,222	14,350,895	9	21,580,222	0.0739
8	Retail Transmission Service (RTS)	99,864	6,341,878	6	16,644,000	0.0635
9	Lighting Service (LS)	16,147	2,691,728	1,072	15,063	0.1667
10	Restricted Lighting Service (RLS)	18,348	3,543,663	1,288	14,245	0.1931
11	Lighting Energy Service (LE)	1,297	85,275	22	58,955	0.0657
12	Traffic Energy Service (TE)	956	82,815	79	12,101	0.0866
13	Special Contracts	256,280	15,964,310	3	85,426,667	0.0623
14	Duplicate Customers			-1,077		
15						
16	Reclassifications and Adjustments		24,822			
17						
18						
19						
20						
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23						
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37						
38	Subtotal	1,138,206	91,550,225	4,124	275,996	0.0804
39	Unbilled	-6,856	-2,835,723			0.4136
40	Total	1,131,350	88,714,502	4,124	274,333	0.0784
41	TOTAL Billed	11,682,233	1,000,738,288	395,312	29,552	0.0857
42	Total Unbilled Rev.(See Instr. 6)	16,742	1,003,242	0	0	0.0599
43	TOTAL	11,698,975	1,001,741,530	395,312	29,594	0.0856

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 304 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $15,490,705

Schedule Page: 304 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $1,524

Schedule Page: 304 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $879

Schedule Page: 304 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $8,750

Schedule Page: 304 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $10,487

Schedule Page: 304 Line No.: 8 Column: c
Includes Fuel Adjustment Clause of $258

Schedule Page: 304 Line No.: 9 Column: a
Average number of customers served under this rate schedule has been adjusted to avoid duplication.

Schedule Page: 304 Line No.: 11 Column: a
Reclassification between FERC accounts and net billing adjustments for prior periods

Schedule Page: 304.1 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $323

Schedule Page: 304.1 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $4,794,299

Schedule Page: 304.1 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $7,736,816

Schedule Page: 304.1 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $2,363,042

Schedule Page: 304.1 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $5,865,761

Schedule Page: 304.1 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $649,345

Schedule Page: 304.1 Line No.: 8 Column: c
Includes Fuel Adjustment Clause of $2,686,719

Schedule Page: 304.1 Line No.: 9 Column: c
Includes Fuel Adjustment Clause of $107,089

Schedule Page: 304.1 Line No.: 10 Column: c
Includes Fuel Adjustment Clause of $62,669

Schedule Page: 304.1 Line No.: 11 Column: c
Includes Fuel Adjustment Clause of $15

Schedule Page: 304.1 Line No.: 13 Column: a
Average number of customers served under this rate schedule has been adjusted to avoid duplication.

Schedule Page: 304.1 Line No.: 15 Column: a
Reclassification between FERC accounts and net billing adjustments for prior periods

Schedule Page: 304.1 Line No.: 15 Column: c
Includes Fuel Adjustment Clause of $1,774

Schedule Page: 304.2 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $391

Schedule Page: 304.2 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $26,330

Schedule Page: 304.2 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $26,009

Schedule Page: 304.2 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $8,770

Schedule Page: 304.2 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $7,877

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 304.2 Line No.: 7 Column: a

Average number of customers served under this rate schedule has been adjusted to avoid duplication.

Schedule Page: 304.2 Line No.: 9 Column: a

Reclassification between FERC accounts and net billing adjustments for prior periods

Schedule Page: 304.3 Line No.: 2 Column: c

Includes Fuel Adjustment Clause of $4,932

Schedule Page: 304.3 Line No.: 3 Column: c

Includes Fuel Adjustment Clause of $428,033

Schedule Page: 304.3 Line No.: 4 Column: c

Includes Fuel Adjustment Clause of $1,194,059

Schedule Page: 304.3 Line No.: 5 Column: c

Includes Fuel Adjustment Clause of $219,945

Schedule Page: 304.3 Line No.: 6 Column: c

Includes Fuel Adjustment Clause of $232,335

Schedule Page: 304.3 Line No.: 7 Column: c

Includes Fuel Adjustment Clause of $773,658

Schedule Page: 304.3 Line No.: 8 Column: c

Includes Fuel Adjustment Clause of $383,784

Schedule Page: 304.3 Line No.: 9 Column: c

Includes Fuel Adjustment Clause of $56,470

Schedule Page: 304.3 Line No.: 10 Column: c

Includes Fuel Adjustment Clause of $66,387

Schedule Page: 304.3 Line No.: 11 Column: c

Includes Fuel Adjustment Clause of $4,696

Schedule Page: 304.3 Line No.: 12 Column: c

Includes Fuel Adjustment Clause of $3,602

Schedule Page: 304.3 Line No.: 13 Column: c

Includes Fuel Adjustment Clause of $1,089,846

Schedule Page: 304.3 Line No.: 14 Column: a

Average number of customers served under this rate schedule has been adjusted to avoid duplication.

Schedule Page: 304.3 Line No.: 16 Column: a

Reclassification between FERC accounts and net billing adjustments for prior periods

Schedule Page: 304.3 Line No.: 16 Column: c

Includes Fuel Adjustment Clause of $(215)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Ameren Energy Marketing Company	OS	(3)	N/A	N/A	N/A
2	American Electric Power Service Corp.	OS	(3)	N/A	N/A	N/A
3	Brookfield Energy Marketing LP	OS	(3)	N/A	N/A	N/A
4	Cargill Power Markets, LLC	OS	(3)	N/A	N/A	N/A
5	East Kentucky Power Cooperative	OS	(3)	N/A	N/A	N/A
6	East Kentucky Power Cooperative	AD	(3)	N/A	N/A	N/A
7	East Kentucky Power Cooperative	OS	(3)	N/A	N/A	N/A
8	ETC Endure Energy, LLC	OS	(3)	N/A	N/A	N/A
9	Exelon Generation Company, LLC	OS	(3)	N/A	N/A	N/A
10	Illinois Municipal Electric Agency	OS	(5)	N/A	N/A	N/A
11	Illinois Municipal Electric Agency	OS	(3)	N/A	N/A	N/A
12	Indiana Municipal Power Agency	OS	(7)	N/A	N/A	N/A
13	Indiana Municipal Power Agency	OS	(3)	N/A	N/A	N/A
14	Kentucky Municipal Power Agency	OS	(6)	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
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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.
842		36,284		36,284	1
1,426		61,614		61,614	2
377		14,574		14,574	3
32,503		1,538,435		1,538,435	4
7,379		315,735		315,735	5
			432	432	6
64		6,653		6,653	7
24,083		1,029,058		1,029,058	8
312		14,820		14,820	9
440		15,515		15,515	10
2,430		163,001		163,001	11
3,267		127,551		127,551	12
3,066		239,980		239,980	13
1,179		44,765		44,765	14
0	0	0	0	0	
2,779,341	0	78,580,641	237	78,580,878	
2,779,341	**0**	**78,580,641**	**237**	**78,580,878**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Kentucky Utilities Company	SF	(1)	N/A	N/A	N/A
2	Midcontinent Independent System Oper	OS	(3)	N/A	N/A	N/A
3	Midwest Independent Transm. System Oper	AD	(3)	N/A	N/A	N/A
4	Midwest Independent Transm. System Oper	OS	(3)	N/A	N/A	N/A
5	Owensboro Municipal Utilities	OS	(6)	N/A	N/A	N/A
6	PJM Settlement, Inc.	OS	(3)	N/A	N/A	N/A
7	Tenaska Power Services Company	OS	(3)	N/A	N/A	N/A
8	Tennessee Valley Authority	OS	(3)	N/A	N/A	N/A
9	The Energy Authority, Inc.	OS	(3)	N/A	N/A	N/A
10	Westar Energy, Inc.	OS	(3)	N/A	N/A	N/A
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
2,329,588		59,187,988		59,187,988	1
47,726		1,969,678		1,969,678	2
-8			-195	-195	3
8,677		293,135		293,135	4
5,175		200,007		200,007	5
161,616		7,204,088		7,204,088	6
10,252		411,319		411,319	7
138,266		5,680,836		5,680,836	8
93		3,733		3,733	9
588		21,872		21,872	10
					11
					12
					13
					14
0	0	0	0	0	
2,779,341	0	78,580,641	237	78,580,878	
2,779,341	**0**	**78,580,641**	**237**	**78,580,878**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 Column: a

Effective December 2, 2013, Ameren Energy Marketing Company changed its name to Illinois Power Marketing Company.

Schedule Page: 310 Line No.: 1 Column: b

Market Based Sale

Schedule Page: 310 Line No.: 1 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310 Line No.: 2 Column: b

Market Based Sale

Schedule Page: 310 Line No.: 2 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310 Line No.: 3 Column: a

Effective April 3, 2013, contract assigned from Brookfield Energy Marketing Inc. changed to Brookfield Energy Marketing LP.

Schedule Page: 310 Line No.: 3 Column: b

Market Based Sale

Schedule Page: 310 Line No.: 3 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310 Line No.: 4 Column: b

Market Based Sale

Schedule Page: 310 Line No.: 4 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310 Line No.: 5 Column: b

Market Based Sale

Schedule Page: 310 Line No.: 5 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310 Line No.: 6 Column: b

December 2012 correction made in 2013

Schedule Page: 310 Line No.: 6 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310 Line No.: 6 Column: j

December 2012 correction made in 2013

Schedule Page: 310 Line No.: 7 Column: b

Emergency Power

Schedule Page: 310 Line No.: 7 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310 Line No.: 8 Column: b

Market Based Sale

Schedule Page: 310 Line No.: 8 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310 Line No.: 9 Column: b

Market Based Sale

Schedule Page: 310 Line No.: 9 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310 Line No.: 10 Column: b

Cost Based Sale

Schedule Page: 310 Line No.: 10 Column: c

(5) LGE CBR Tariff First Revised Service Agreement No. 3

Schedule Page: 310 Line No.: 11 Column: b

Energy Imbalance

Schedule Page: 310 Line No.: 11 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310 Line No.: 12 Column: b

Cost Based Sale

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2013/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 12 Column: c
(7) LGE CBR Tariff Service Agreement No. 4

Schedule Page: 310 Line No.: 13 Column: b
Energy Imbalance

Schedule Page: 310 Line No.: 13 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310 Line No.: 14 Column: b
Energy Imbalance

Schedule Page: 310 Line No.: 14 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4

Schedule Page: 310.1 Line No.: 1 Column: a
LG&E and KU are owned by PPL Corporation.

Schedule Page: 310.1 Line No.: 1 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.: 2 Column: a
Effective April 26, 2013, Midwest Independent Transmission System Operator, Inc. changed its name to Midcontinent Independent System Operator, Inc.

Schedule Page: 310.1 Line No.: 2 Column: b
Market Based Sale

Schedule Page: 310.1 Line No.: 2 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.1 Line No.: 3 Column: a
Effective April 26, 2013, Midwest Independent Transmission System Operator, Inc. changed its name to Midcontinent Independent System Operator, Inc.

Schedule Page: 310.1 Line No.: 3 Column: b
November 2012 correction made in 2013

Schedule Page: 310.1 Line No.: 3 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.1 Line No.: 3 Column: g
November 2012 correction made in 2013

Schedule Page: 310.1 Line No.: 3 Column: j
November 2012 correction made in 2013

Schedule Page: 310.1 Line No.: 4 Column: a
Effective April 26, 2013, Midwest Independent Transmission System Operator, Inc. changed its name to Midcontinent Independent System Operator, Inc.

Schedule Page: 310.1 Line No.: 4 Column: b
Market Based Sale

Schedule Page: 310.1 Line No.: 4 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.1 Line No.: 5 Column: b
Energy Imbalance

Schedule Page: 310.1 Line No.: 5 Column: c
(6) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4

Schedule Page: 310.1 Line No.: 6 Column: b
Market Based Sale

Schedule Page: 310.1 Line No.: 6 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.1 Line No.: 7 Column: b
Market Based Sale

Schedule Page: 310.1 Line No.: 7 Column: c
(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.1 Line No.: 8 Column: b
Market Based Sale

Schedule Page: 310.1 Line No.: 8 Column: c

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.1 Line No.: 9 Column: b

Market Based Sale

Schedule Page: 310.1 Line No.: 9 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff

Schedule Page: 310.1 Line No.: 10 Column: b

Market Based Sale

Schedule Page: 310.1 Line No.: 10 Column: c

(3) LGE and KU Joint MBRT Short Form Tariff

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	3,598,199	2,983,020
5	(501) Fuel	363,029,887	364,775,584
6	(502) Steam Expenses	34,031,656	35,655,779
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	858,520	769,095
10	(506) Miscellaneous Steam Power Expenses	18,483,144	18,919,832
11	(507) Rents	54,405	66,552
12	(509) Allowances	134,464	43,758
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	420,190,275	423,213,620
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,873,217	3,655,560
16	(511) Maintenance of Structures	2,153,540	2,475,768
17	(512) Maintenance of Boiler Plant	43,179,131	40,119,661
18	(513) Maintenance of Electric Plant	10,465,693	11,876,627
19	(514) Maintenance of Miscellaneous Steam Plant	1,688,779	1,905,774
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	60,360,360	60,033,390
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	480,550,635	483,247,010
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	116,451	110,075
45	(536) Water for Power	38,914	38,567
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses	250,173	220,012
48	(539) Miscellaneous Hydraulic Power Generation Expenses	120,692	118,002
49	(540) Rents	341,326	357,543
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	867,556	844,199
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		344
54	(542) Maintenance of Structures	282,571	173,642
55	(543) Maintenance of Reservoirs, Dams, and Waterways	552,874	361,895
56	(544) Maintenance of Electric Plant	318,172	244,525
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,040	1,939
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	1,155,657	782,345
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	2,023,213	1,626,544

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	55,723	50,433
63	(547) Fuel	16,005,162	21,140,573
64	(548) Generation Expenses	201,025	205,627
65	(549) Miscellaneous Other Power Generation Expenses	30,935	31,829
66	(550) Rents	14,948	21,836
67	TOTAL Operation (Enter Total of lines 62 thru 66)	16,307,793	21,450,298
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	20,611	26,585
70	(552) Maintenance of Structures	99,485	97,439
71	(553) Maintenance of Generating and Electric Plant	812,094	1,102,219
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	78,970	126,273
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,011,160	1,352,516
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	17,318,953	22,802,814
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	48,124,184	52,477,768
77	(556) System Control and Load Dispatching	1,418,728	1,521,043
78	(557) Other Expenses	944,422	817,221
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	50,487,334	54,816,032
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	550,380,135	562,492,400
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	908,744	1,045,617
84			
85	(561.1) Load Dispatch-Reliability	1,843,459	1,701,691
86	(561.2) Load Dispatch-Monitor and Operate Transmission System		
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services		65
89	(561.5) Reliability, Planning and Standards Development	484,452	433,639
90	(561.6) Transmission Service Studies	4,023	-2,450
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		5
93	(562) Station Expenses	1,487,980	1,245,245
94	(563) Overhead Lines Expenses	209,101	146,488
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	790,386	1,880,039
97	(566) Miscellaneous Transmission Expenses	5,643,897	6,861,089
98	(567) Rents	30,038	28,679
99	TOTAL Operation (Enter Total of lines 83 thru 98)	11,402,080	13,340,107
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	1,931	2,493
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	1,515,641	1,565,453
108	(571) Maintenance of Overhead Lines	1,259,237	873,026
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	106,330	26,320
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,883,139	2,467,292
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	14,285,219	15,807,399

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	-291,297	751,704
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	-291,297	751,704
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)	-291,297	751,704
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,775,521	1,995,747
135	(581) Load Dispatching	754,507	730,593
136	(582) Station Expenses	1,202,910	1,146,675
137	(583) Overhead Line Expenses	4,812,185	5,014,132
138	(584) Underground Line Expenses	516,787	462,346
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	6,360,835	6,537,575
141	(587) Customer Installations Expenses	-183,095	-169,586
142	(588) Miscellaneous Expenses	3,340,086	2,949,181
143	(589) Rents	16,708	11,976
144	TOTAL Operation (Enter Total of lines 134 thru 143)	18,596,444	18,678,639
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	75,828	133,671
147	(591) Maintenance of Structures	751,679	802,175
148	(592) Maintenance of Station Equipment	991,783	1,024,774
149	(593) Maintenance of Overhead Lines	22,008,878	19,426,628
150	(594) Maintenance of Underground Lines	1,756,547	1,517,247
151	(595) Maintenance of Line Transformers	187,301	199,109
152	(596) Maintenance of Street Lighting and Signal Systems	318,493	233,603
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant	388,656	386,984
155	TOTAL Maintenance (Total of lines 146 thru 154)	26,479,165	23,724,191
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	45,075,609	42,402,830
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,081,490	958,035
160	(902) Meter Reading Expenses	2,264,977	2,181,581
161	(903) Customer Records and Collection Expenses	5,377,613	5,576,359
162	(904) Uncollectible Accounts	1,426,633	1,415,587
163	(905) Miscellaneous Customer Accounts Expenses	167,827	361,692
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	10,318,540	10,493,254

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	205,776	189,829
168	(908) Customer Assistance Expenses	14,119,699	11,053,392
169	(909) Informational and Instructional Expenses	387,681	209,541
170	(910) Miscellaneous Customer Service and Informational Expenses	345,696	425,901
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	15,058,852	11,878,663
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	41,970	
176	(913) Advertising Expenses		1,385
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	41,970	1,385
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	20,447,687	17,083,687
182	(921) Office Supplies and Expenses	5,254,890	5,643,955
183	(Less) (922) Administrative Expenses Transferred-Credit	2,907,439	2,397,160
184	(923) Outside Services Employed	11,800,895	4,243,017
185	(924) Property Insurance	5,254,956	4,867,967
186	(925) Injuries and Damages	1,714,860	1,873,239
187	(926) Employee Pensions and Benefits	35,212,502	32,865,537
188	(927) Franchise Requirements	31,232	30,725
189	(928) Regulatory Commission Expenses	1,016,143	1,064,777
190	(929) (Less) Duplicate Charges-Cr.	221,463	119,930
191	(930.1) General Advertising Expenses	565,651	419,961
192	(930.2) Miscellaneous General Expenses	2,785,730	2,952,216
193	(931) Rents	1,993,192	1,691,225
194	TOTAL Operation (Enter Total of lines 181 thru 193)	82,948,836	70,219,216
195	Maintenance		
196	(935) Maintenance of General Plant	3,756,003	9,242,206
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	86,704,839	79,461,422
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	721,573,867	723,289,057

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 320 Line No.: 90 Column: c

The credit is due to transmission study adjustments that were performed for and billed to Southwest Power Pool and Transerv International.

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.: 141 Column: b

The credit is due to meter tampering charges billed to customers to offset cost of meter maintenance. Cost is recorded in several other accounts.

Schedule Page: 320 Line No.: 141 Column: c

The credit is due to meter tampering charges billed to customers to offset cost of meter maintenance. Cost is recorded in several other accounts.

Schedule Page: 320 Line No.: 184 Column: b

Amortization expense related to Information Technology software maintenance contracts, which was previously classified as Maintenance of General Plant (935), is considered to be a service to the company and these related expenses were moved to Outside Services Employed (923).

Schedule Page: 320 Line No.: 196 Column: b

Amortization expense related to Information Technology software maintenance contracts, which was previously classified as Maintenance of General Plant (935), is considered to be a service to the company and these related expenses were moved to Outside Services Employed (923).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Ameren Energy Marketing Company	OS	(1)	N/A	N/A	N/A
2	Cargill Power Markets, LLC	OS	(1)	N/A	N/A	N/A
3	Illinois Municipal Electric Agency	OS	(8)	N/A	N/A	N/A
4	Indiana Municipal Power Agency	OS	(8)	N/A	N/A	N/A
5	Kentucky Municipal Power Agency	OS	(3)	N/A	N/A	N/A
6	Kentucky Utilities Company	SF	(2)	N/A	N/A	N/A
7	Ohio Valley Electric Corporation	OS	(6)	N/A	N/A	N/A
8	Ohio Valley Electric Corporation	AD	(6)	N/A	N/A	N/A
9	Owensboro Municipal Utilities	OS	(3)	N/A	N/A	N/A
10	PJM Interconnection Association	OS	(1)	N/A	N/A	N/A
11	Tennessee Valley Authority	OS	(10)	N/A	N/A	N/A
12	Tennessee Valley Authority	OS	(4)	N/A	N/A	N/A
13	Inadvertent Interchange			N/A	N/A	N/A
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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				162		162	1
596				11,888		11,888	2
1,037				3,757		3,757	3
944				4,380		4,380	4
2,972				98,101		98,101	5
307,382				9,198,664		9,198,664	6
590,677			20,251,897	17,990,294		38,242,191	7
					211,670	211,670	8
317				11,872		11,872	9
2,845				103,047		103,047	10
10,826				225,659		225,659	11
106				12,793		12,793	12
	4,051	240,510					13
							14
917,707	4,051	240,510	20,251,897	27,660,617	211,670	48,124,184	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: a
Effective December 2, 2013, Ameren Energy Marketing Company changed its name to Illinois Power Marketing Company.

Schedule Page: 326 Line No.: 1 Column: b
Market Based Purchase

Schedule Page: 326 Line No.: 1 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission

Schedule Page: 326 Line No.: 2 Column: b
Market Based Purchase

Schedule Page: 326 Line No.: 2 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission

Schedule Page: 326 Line No.: 3 Column: b
Energy Imbalance

Schedule Page: 326 Line No.: 3 Column: c
(8) FERC-approved tariff and/or rate schedule as on file with the Commission. Participation Agreement dated February 9, 2004.

Schedule Page: 326 Line No.: 4 Column: b
Energy Imbalance

Schedule Page: 326 Line No.: 4 Column: c
(8) FERC-approved tariff and/or rate schedule as on file with the Commission. Participation Agreement dated February 9, 2004.

Schedule Page: 326 Line No.: 5 Column: b
Energy Imbalance

Schedule Page: 326 Line No.: 5 Column: c
(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4

Schedule Page: 326 Line No.: 6 Column: a
LG&E and KU are owned by PPL Corporation.

Schedule Page: 326 Line No.: 6 Column: c
(2) FERC Rate Schedule No. 1. The Power Supply System Agreement, FERC Docket No. ER98-111-000

Schedule Page: 326 Line No.: 7 Column: a
Intercompany Power Agreement dated September 10, 2010. The Company owns 5.63% 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 Line No.: 7 Column: b
Surplus Power

Schedule Page: 326 Line No.: 7 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 Line No.: 8 Column: a
Intercompany Power Agreement dated September 10, 2010. The Company owns 5.63% 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 Line No.: 8 Column: b
December 2012 true-up of accrual estimate for both energy and demand charges booked in 2013.

Schedule Page: 326 Line No.: 8 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 Line No.: 8 Column: l
December 2012 true-up of accrual estimate for both energy, $38,939, and demand charges

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

$172,731 made in 2013.

Schedule Page: 326 Line No.: 9 Column: b

Energy Imbalance

Schedule Page: 326 Line No.: 9 Column: c

(3) LGE and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4

Schedule Page: 326 Line No.: 10 Column: b

Market Based Purchase

Schedule Page: 326 Line No.: 10 Column: c

(1) FERC-approved tariff and/or rate schedule as on file with the Commission

Schedule Page: 326 Line No.: 11 Column: b

Market Based Purchase

Schedule Page: 326 Line No.: 11 Column: c

(10) FERC Electric Rate Schedule No. 28 Interchange Agreement dated July 1, 1977

Schedule Page: 326 Line No.: 12 Column: b

Emergency Power

Schedule Page: 326 Line No.: 12 Column: c

(4) TEE Contingency Reserve Sharing Agreement dated November 20, 2009

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	FNO
2	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	AD
3	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	NF
4	Indiana Municipal Power Agency	Indiana Municipal Power Agency	Midwest ISO and PJM	OLF
5	Indiana Municipal Power Agency	Indiana Municipal Power Agency	Midwest ISO and PJM	LFP
6	Illinois Municipal Electric Agency	IL Municipal Electric Agency	Midwest ISO	OLF
7	Illinois Municipal Electric Agency	IL Municipal Electric Agency	Midwest ISO	LFP
8	Cargill Power Markets, LLC	Various	Various	SFP
9	Cargill Power Markets, LLC	Various	Various	NF
10	LG&E/KU	Various	Various	NF
11	LG&E/KU	Various	Various	SFP
12	LG&E/KU	Various	Various	LFP
13	Hoosier Energy	Midwest ISO	Hoosier Energy	FNO
14	Hoosier Energy	Midwest ISO	Hoosier Energy	AD
15	Kentucky Municipal Power Agency	Midwest ISO	LG&E	FNO
16	Kentucky Municipal Power Agency	Midwest ISO	LG&E	NF
17	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	FNO
18	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	LFP
19	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	SFP
20	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	NF
21	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	AD
22	Big Rivers Electric Corporation	Big Rivers Electric Corporation	Big Rivers Electric Corporation	FNO
23	Constellation Energy Commodities Group	PJM	Tennessee Valley Authority	SFP
24	Ameren Energy Marketing Company	Various	Various	SFP
25	Ameren Energy Marketing Company	Various	Various	NF
26	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	LFP
27	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	AD
28	Various	Various	Various	AD
29	City of Barbourville	Various	City of Barbourville	FNO
30	City of Bardstown	Various	City of Bardstown	FNO
31	City of Bardwell	Various	City of Bardwell	FNO
32	City of Benham	Various	City of Benham	FNO
33	City of Berea	Various	City of Berea	FNO
34	City of Corbin	Various	City of Corbin	FNO
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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)	
LGE/KU Joint	East Kentucky Power	East Kentucky Power	58	332,104	324,521	1
LGE/KU Joint	East Kentucky Power	East Kentucky Power				2
LGE/KU Joint	East Kentucky Power	East Kentucky Power				3
LGE/KU Joint	Trimble Co. Unit 1	Midwest ISO and PJM		476,175	476,175	4
LGE/KU Joint	Trimble Co. Unit 2	Midwest ISO and PJM		546,133	546,133	5
LGE/KU Joint	Trimble Co. Unit 1	Midwest ISO		457,014	457,014	6
LGE/KU Joint	Trimble Co. Unit 2	Midwest ISO		513,569	513,569	7
LGE/KU Joint	Various	Various	19	160,361	155,359	8
LGE/KU Joint	Various	Various		10,342	10,004	9
LGE/KU Joint	Various	Various				10
LGE/KU Joint	Various	Various	11			11
LGE/KU Joint	Various	Various	8			12
LGE/KU Joint	Midwest ISO	Hoosier Energy	2	11,697	11,697	13
LGE/KU Joint	Midwest ISO	Hoosier Energy				14
SA 13	Various	LGEE.KMPA	37	227,007	222,717	15
SA 13	Various	LGEE.KMPA				16
SA 15	Owensboro Municipal	Various	44	1,389		17
LGE/KU Joint	Owensboro Municipal	Various	67	567,577	555,290	18
LGE/KU Joint	Owensboro Municipal	Various	4			19
LGE/KU Joint	Owensboro Municipal	Various				20
LGE/KU Joint	Owensboro Municipal	Various				21
LGE/KU Joint	Big Rivers Electric	Big Rivers Electric	3	20,866	20,347	22
LGE/KU Joint	PJM	TVA	11	41,898	40,676	23
LGE/KU Joint	Various	Various	24	86,516	82,716	24
LGE/KU Joint	Various	Various				25
LGE/KU Joint	TVA	TVA	10	53,351	53,351	26
LGE/KU Joint	TVA	TVA				27
LGE/KU Joint	Various	Various				28
184	Various	City of Barbourville	62			29
185	Various	City of Bardstown	119			30
186	Various	City of Bardwell	5			31
187	Various	City of Benham	5			32
197	Various	City of Berea	85			33
188	Various	City of Corbin	55			34
			1,460	**3,505,999**	**3,469,569**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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 Falmouth	Various	City of Falmouth	FNO
2	City of Frankfort	Various	City of Frankfort	FNO
3	City of Madisonville	Various	City of Madisonville	FNO
4	City of Nicholasville	Various	City of Nicholasville	FNO
5	City of Paris	Various	City of Paris	FNO
6	City of Providence	Various	City of Providence	FNO
7				
8				
9				
10				
11				
12				
13				
14				
15				
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31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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.
189	Various	City of Falmouth	13			1
190	Various	City of Frankfort	449			2
161	Various	City of Madisonville	183			3
157	Various	City of Nicholasvill	122			4
83	Various	City of Paris	43			5
195	Various	City of Providence	21			6
						7
						8
						9
						10
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						13
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						29
						30
						31
						32
						33
						34
			1,460	**3,505,999**	**3,469,569**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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.
1,783,447		180,092	1,963,539	1
9,629		805	10,434	2
	-1,933		-1,933	3
				4
				5
				6
				7
343,332		37,011	380,343	8
	25,223	2,099	27,322	9
	577,424	44,470	621,894	10
49,806		3,841	53,647	11
127,010		12,907	139,917	12
23,709		2,422	26,131	13
-2,645			-2,645	14
606,914		244,128	851,042	15
	307	22	329	16
557,909		262,531	820,440	17
1,084,407		110,704	1,195,111	18
82,466		7,339	89,805	19
	290,121	22,256	312,377	20
-94,598		-9,376	-103,974	21
56,745		5,690	62,435	22
114,781		13,514	128,295	23
200,291		15,586	215,877	24
	9,974	688	10,662	25
161,719		16,178	177,897	26
969		81	1,050	27
-316,989	-479,495	-11	-796,495	28
82,142		3,609	85,751	29
154,021		6,742	160,763	30
7,572		330	7,902	31
5,746		258	6,004	32
93,024		4,107	97,131	33
75,766		3,309	79,075	34
6,326,933	**421,621**	**1,040,423**	**7,788,977**	

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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.
15,214		656	15,870	1
611,891		26,855	638,746	2
248,578		10,829	259,407	3
164,778		7,271	172,049	4
52,743		2,315	55,058	5
26,556		1,165	27,721	6
				7
				8
				9
				10
				11
				12
				13
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				31
				32
				33
				34
6,326,933	**421,621**	**1,040,423**	**7,788,977**	

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2013/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: m

The total consists of East Kentucky Power Cooperative Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 2 Column: k

The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 2 Column: m

The total consists of a true-up of prior periods for East Kentucky Power Cooperative Schedule 1 and Schedule 2 charges related to firm transmission.

Schedule Page: 328 Line No.: 3 Column: l

The total consists of the amortization of a regulatory asset authorized by the settlement agreement between LG&E, KU and East Kentucky Power Cooperative regarding the Network Integration Transmission Service Agreement. FERC Docket Nos. ER06-1458-000, ER06-1458-001 and ER06-1458-002.

Schedule Page: 328 Line No.: 4 Column: a

LG&E transmits electricity for Indiana Municipal Power Agency (IMPA) from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMPA. This agreement was reached between LG&E and IMPA as a result of LG&E's exit from the MISO.

Schedule Page: 328 Line No.: 4 Column: d

The OLF transmission service agreement between LG&E and Indiana Municipal Power Agency has no expiration date.

Schedule Page: 328 Line No.: 5 Column: a

LG&E transmits electricity for Indiana Municipal Power Agency (IMPA) from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMPA. This agreement was reached between LG&E and IMPA as a result of LG&E's exit from the MISO.

Schedule Page: 328 Line No.: 5 Column: d

The LFP transmission service agreement between LG&E and Indiana Municipal Power Agency has a termination date of 1/01/2020 for Trimble County Unit 2.

Schedule Page: 328 Line No.: 6 Column: a

LG&E transmits electricity for Illinois Municipal Electric Agency (IMEA) from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMEA. This agreement was reached between LG&E and IMEA as a result of LG&E's exit from the MISO.

Schedule Page: 328 Line No.: 6 Column: d

The OLF transmission service agreement between LG&E and Illinois Municipal Electric Agency has a termination date of 3/01/2023 for Trimble County Unit 1.

Schedule Page: 328 Line No.: 7 Column: a

LG&E transmits electricity for Illinois Municipal Electric Agency (IMEA) from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMEA. This agreement was reached between LG&E and IMEA as a result of LG&E's exit from the MISO.

Schedule Page: 328 Line No.: 7 Column: d

The LFP transmission service agreement between LG&E and Illinois Municipal Electric Agency has a termination date of 1/01/2020 for Trimble County Unit 2.

Schedule Page: 328 Line No.: 8 Column: m

The total consists of Cargill Power Markets, LLC Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 9 Column: m

The total consists of Cargill Power Markets, LLC Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 10 Column: a

LG&E and KU are owned by PPL.

Schedule Page: 328 Line No.: 10 Column: m

The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 11 Column: a

LG&E and KU are owned by PPL.

Schedule Page: 328 Line No.: 11 Column: m

The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 12 Column: a

LG&E and KU are owned by PPL.

Schedule Page: 328 Line No.: 12 Column: d

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2013/Q4

FOOTNOTE DATA

Long-term Firm purchases by LG&E and KU take place under the Open Access Transmission Tariff with intercompany allocations for revenues and expenses determined by the Transmission Coordination Agreement between the Companies. The Tariff is evergreen and the Transmission Coordination Agreement automatically renews unless terminated.

Schedule Page: 328 Line No.: 12 Column: m

The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 13 Column: m

The total consists of Hoosier Energy Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 14 Column: k

The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 15 Column: m

The total consists of Kentucky Municipal Power Agency Schedule 1, Schedule 2, Schedule 3, Schedule 5 and Schedule 6 charges.

Schedule Page: 328 Line No.: 16 Column: m

The total consists of Kentucky Municipal Power Agency Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 17 Column: m

The total consists of Owensboro Municipal Utilities Schedule 1, Schedule 2, Schedule 3, Schedule 5 and Schedule 6 charges.

Schedule Page: 328 Line No.: 18 Column: m

The total consists of Owensboro Municipal Utilities Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 19 Column: m

The total consists of Owensboro Municipal Utilities Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 20 Column: m

The total consists of Owensboro Municipal Utilities Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 21 Column: k

The total consists of a refund pursuant to FERC Docket No. EL13-79-000.

Schedule Page: 328 Line No.: 21 Column: m

The total consists of a refund of Schedule 1 and Schedule 2 charges pursuant to FERC Docket No. EL13-79-000.

Schedule Page: 328 Line No.: 22 Column: m

The total consists of Big Rivers Electric Corporation Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 23 Column: m

The total consists of Constellation Energy Commodities Group Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 24 Column: m

The total consists of Ameren Energy Marketing Company Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 25 Column: m

The total consists of Ameren Energy Marketing Company Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 26 Column: m

The total consists of Tennessee Valley Authority Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 27 Column: k

The total consists of a true-up of prior periods.

Schedule Page: 328 Line No.: 27 Column: m

The total consists of Tennessee Valley Authority Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 28 Column: k

True-ups made in 2013 related to OATT rate adjustments for various counterparties.

Schedule Page: 328 Line No.: 28 Column: l

True-ups made in 2013 related to OATT rate adjustments for various counterparties.

Schedule Page: 328 Line No.: 28 Column: m

True-ups made in 2013 related to OATT rate adjustments for various counterparties.

Schedule Page: 328 Line No.: 29 Column: m

The total consists of City of Barbourville Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 30 Column: m

The total consists of City of Bardstown Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 31 Column: m

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FOOTNOTE DATA

The total consists of City of Bardwell Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 32 Column: m

The total consists of City of Benham Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 33 Column: m

The total consists of City of Berea Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 34 Column: m

The total consists of City of Corbin Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 1 Column: m

The total consists of City of Falmouth Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 2 Column: m

The total consists of City of Frankfort Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 3 Column: m

The total consists of City of Madisonville Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 4 Column: m

The total consists of City of Nicholasville Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 5 Column: m

The total consists of City of Paris Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 6 Column: m

The total consists of City of Providence Schedule 1 and Schedule 2 charges.

Schedule Page: 328.1 Line No.: 6 Column: n

This footnote is not to reference this cell, but the total on Line No.: 15, Column: n.

The total amount does not agree to Schedule Page: 300, Line No.: 22, Column: b due to intracompany transmission revenues that must be eliminated:

Schedule Page: 330, Line No.: 35, Column: n	$	7,788,977
Elimination of intracompany transmission revenues		(344,749)
Schedule Page: 300, Line No.: 22, Column: b	$	7,444,228

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	EKPC	SFP			1,577			1,577
2	EKPC	NF					472	472
3	KU/LG&E	LFP	-142,432	-142,432	-118,165			-118,165
4	KU/LG&E	SFP			-90,607			-90,607
5	KU/LG&E	NF	371,681	371,681		1,183,075	85,324	1,268,399
6	PJM Interconnect	SFP	4,827	4,827	13,489			13,489
7	PJM Interconnect	NF	3,196	3,196		2,141	53,647	55,788
8	PJM Interconnect	AD			94		3,022	3,116
9	TVA	NF				1,066		1,066
10								
11								
12								
13								
14								
15								
16								
	TOTAL		237,272	237,272	-193,612	1,186,282	142,465	1,135,135

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 332 Line No.: 2 Column: g

The total consists of Schedule 1 and Schedule 2 charges

Schedule Page: 332 Line No.: 3 Column: a

LG&E and KU are owned by PPL.

Schedule Page: 332 Line No.: 3 Column: e

True-ups made in the first quarter of 2013 related to OATT rate adjustments made in the fourth quarter of 2012.

Schedule Page: 332 Line No.: 4 Column: a

LG&E and KU are owned by PPL.

Schedule Page: 332 Line No.: 4 Column: e

True-ups made in the first quarter of 2013 related to OATT rate adjustments made in the fourth quarter of 2012.

Schedule Page: 332 Line No.: 5 Column: a

LG&E and KU are owned by PPL.

Schedule Page: 332 Line No.: 5 Column: g

The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 7 Column: g

The total consists of Schedule 1, Schedule 2 and Black Start service charges.

Schedule 1 Non-firm	$	51,064
Schedule 2 Non-firm		1,490
Black Start Service Non-firm		1,093
	$	53,647

Schedule Page: 332 Line No.: 8 Column: e

The total consists of true-ups of charges for prior periods.

Schedule Page: 332 Line No.: 8 Column: g

The total consists of Schedule 1, Schedule 2 and Black Start service charges.

Schedule 1 Non-firm	$	1,805
Schedule 2 Non-firm		1,108
Black Start Service Non-firm		109
	$	3,022

Schedule Page: 332 Line No.: 9 Column: h

This footnote is not to reference this cell, but the total on Line No.: 17, Column: h.

The total amount does not agree to Schedule page: 321, Line No.: 96, Column: b due to intracompany transmission expenses that must be eliminated:

Schedule Page: 332, Line No.: 17, Column: h	$	1,135,135
Elimination of intracompany transmission expenses		(344,749)
Schedule page: 321, Line No.: 96, Column: b	$	790,386

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Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	458,131
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	1,600,858
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Market Research and Consulting Expenses:	
7	Bellomy Research	127,055
8	Vision Critical Communications US Inc	64,657
9	Bluegrass Mailing Data and Fulfillment Services	14,085
10	Chartwell Inc	8,471
11	IBEW Non-Billable Charges	52,372
12	Swap Termination Amortization	307,079
13	Miscellaneous	153,022
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
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31		
32		
33		
34		
35		
36		
37		
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44		
45		
46	TOTAL	2,785,730

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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					
2	Steam Production Plant	61,820,785				61,820,785
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	1,547,253				1,547,253
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	10,159,894				10,159,894
7	Transmission Plant	5,939,336				5,939,336
8	Distribution Plant	28,382,873				28,382,873
9	Regional Transmission and Market Operation					
10	General Plant	426,960				426,960
11	Common Plant-Electric	7,688,535		5,643,550		13,332,085
12	TOTAL	115,965,636		5,643,550		121,609,186

B. Basis for Amortization Charges

ACCOUNT	RATE	PLANT BALANCE @ 12/31/2013	AMORTIZATION	
330300	14%	$31,558,449	$ 2,413,918	
330310	10%	46,024,346	3,229,632	

			$ 5,643,550	Column (d)

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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	Electric Plant						
13	Elec Intangible Plant	2					
14	Steam Production Plant						
15	310.20 - Land	6,802					
16							
17	311 Strctrs & Imprvmts						
18	0112 Cane Run Unit 1	4,234	100.00	-2.00		100-S1	
19	0121 Cane Run Unit 2	2,103	100.00	-2.00		100-S1	
20	0131 Cane Run Unit 3	3,538	100.00	-2.00		100-S1	
21	0141 Cane Run Unit 4	4,084	100.00	-2.00		100-S1	
22	0142 Cane Run 4 FGD	821	100.00	-2.00		100-S1	
23	0151 Cane Run Unit 5	6,288	100.00	-2.00	0.48	100-S1	4.00
24	0152 Cane Run 5 FGD	1,696	100.00	-2.00		100-S1	
25	0161 Cane Run Unit 6	20,522	100.00	-2.00	6.99	100-S1	4.00
26	0162 Cane Run 6 FGD	2,004	100.00	-2.00		100-S1	
27	0211 Mill Creek Unit 1	19,551	100.00	-8.00	0.97	100-S1	20.00
28	0212 Mill Creek 1 FGD	1,710	100.00	-8.00		100-S1	
29	0221 Mill Creek Unit 2	11,403	100.00	-8.00	0.99	100-S1	21.80
30	0222 Mill Creek 2 FGD	1,393	100.00	-8.00		100-S1	
31	0231 Mill Creek Unit 3	24,491	100.00	-8.00	0.95	100-S1	25.20
32	0232 Mill Creek 3 FGD	363	100.00	-8.00		100-S1	
33	0241 Mill Creek Unit 4	63,502	100.00	-8.00	1.65	100-S1	29.10
34	0242 Mill Creek 4 FGD	5,338	100.00	-8.00	0.50	100-S1	29.20
35	0311 Trimble Cty 1	112,679	100.00	-11.00	1.59	100-S1	36.10
36	0312 Trimble Cty 1 FGD	1,200	100.00	-11.00	1.01	100-S1	36.50
37	0321 Trimble Cty 2	15,343	100.00	-11.00	2.10	100-S1	52.30
38	0322 Trimble Cty 2 FGD	70	100.00	-11.00	2.10	100-S1	52.30
39							
40	312 Boiler Plant Eqpmt						
41	0103 Cane Run Loco	52	25.00			25-R2.5	
42	0104 Cane Run Rail Crs	1,502	25.00		6.89	25-R2.5	3.30
43	0112 Cane Run Unit 1	1,052	50.00	-2.00		50-R1.5	
44	0121 Cane Run Unit 2	132	50.00	-2.00		50-R1.5	
45	0131 Cane Run Unit 3	705	50.00	-2.00		50-R1.5	
46	0141 Cane Run Unit 4	31,590	50.00	-2.00	7.66	50-R1.5	3.90
47	0142 Cane Run 4 FGD	17,322	50.00	-2.00		50-R1.5	
48	0151 Cane Run Unit 5	40,925	50.00	-2.00	13.54	50-R1.5	3.90
49	0152 Cane Run 5 FGD	28,416	50.00	-2.00		50-R1.5	
50	0161 Cane Run Unit 6	63,339	50.00	-2.00	13.69	50-R1.5	3.90

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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	0162 Cane Run 6 FGD	32,497	50.00	-2.00	3.70	50-R1.5	3.90
13	0203 Mill Creek Loco	613	25.00		6.08	25-R2.5	3.20
14	0204 Mill Ck Rail Cars	2,965	25.00		0.36	25-R2.5	10.30
15	0211 Mill Creek Unit 1	62,227	50.00	-8.00	2.53	50-R1.5	18.70
16	0212 Mill Creek 1 FGD	43,620	50.00	-8.00	1.76	50-R1.5	18.90
17	0221 Mill Creek Unit 2	58,692	50.00	-8.00	2.84	50-R1.5	20.20
18	0222 Mill Creek 2 FGD	39,129	50.00	-8.00	1.40	50-R1.5	20.50
19	0231 Mill Creek Unit 3	152,569	50.00	-8.00	2.64	50-R1.5	23.40
20	0232 Mill Creek 3 FGD	63,457	50.00	-8.00	2.17	50-R1.5	23.40
21	0241 Mill Creek Unit 4	253,521	50.00	-8.00	2.54	50-R1.5	26.00
22	0242 Mill Creek 4 FGD	124,916	50.00	-8.00	1.56	50-R1.5	26.20
23	0311 Trimble Cty 1	225,220	50.00	-11.00	2.54	50-R1.5	30.30
24	0312 Trimble Cty 1 FGD	63,999	50.00	-11.00	1.25	50-R1.5	30.30
25	0321 Trimble Cty 2	138,940	50.00	-11.00	2.46	50-R1.5	43.40
26	0322 Trimble Cty 2 FGD	14,991	50.00	-11.00	2.47	50-R1.5	43.40
27							
28	314 Turbogenerator Unt						
29	0112 Cane Run Unit 1	106	60.00	-2.00		60-S1.5	
30	0121 Cane Run Unit 2	20	60.00	-2.00		60-S1.5	
31	0131 Cane Run Unit 3	581	60.00	-2.00		60-S1.5	
32	0141 Cane Run Unit 4	9,484	60.00	-2.00	1.47	60-S1.5	4.00
33	0151 Cane Run Unit 5	7,991	60.00	-2.00	0.83	60-S1.5	4.00
34	0161 Cane Run Unit 6	16,792	60.00	-2.00	8.36	60-S1.5	4.00
35	0211 Mill Creek Unit 1	20,611	60.00	-8.00	1.03	60-S1.5	18.50
36	0221 Mill Creek Unit 2	19,139	60.00	-8.00	1.49	60-S1.5	20.20
37	0231 Mill Creek Unit 3	32,461	60.00	-8.00	1.91	60-S1.5	24.30
38	0241 Mill Creek Unit 4	47,662	60.00	-8.00	1.57	60-S1.5	25.70
39	0311 Trimble Cty 1	57,369	60.00	-11.00	2.18	60-S1.5	33.00
40	0321 Trimble Cty 2	20,863	60.00	-11.00	2.11	60-S1.5	46.60
41							
42	315 Accessry Elec Eqpm						
43	0112 Cane Run Unit 1	1,883	55.00	-2.00		55-S2	
44	0121 Cane Run Unit 2	1,237	55.00	-2.00		55-S2	
45	0131 Cane Run Unit 3	767	55.00	-2.00		55-S2	
46	0141 Cane Run Unit 4	6,239	55.00	-2.00	3.29	55-S2	4.00
47	0142 Cane Run 4 FGD	988	55.00	-2.00		55-S2	
48	0151 Cane Run Unit 5	9,435	55.00	-2.00	11.22	55-S2	4.00
49	0152 Cane Run 5 FGD	2,216	55.00	-2.00		55-S2	
50	0161 Cane Run Unit 6	12,707	55.00	-2.00	10.78	55-S2	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	0162 Cane Run 6 FGD	2,200	55.00	-2.00		55-S2	
13	0211 Mill Creek Unit 1	14,939	55.00	-8.00	2.75	55-S2	18.80
14	0212 Mill Creek 1 FGD	5,542	55.00	-8.00		55-S2	
15	0221 Mill Creek Unit 2	7,669	55.00	-8.00	1.78	55-S2	19.20
16	0222 Mill Creek 2 FGD	4,505	55.00	-8.00		55-S2	
17	0231 Mill Creek Unit 3	15,047	55.00	-8.00	0.92	55-S2	20.80
18	0232 Mill Creek 3 FGD	2,532	55.00	-8.00		55-S2	
19	0241 Mill Creek Unit 4	24,985	55.00	-8.00	1.49	55-S2	23.40
20	0242 Mill Creek 4 FGD	5,865	55.00	-8.00	0.38	55-S2	23.10
21	0311 Trimble Cty 1	49,077	55.00	-11.00	2.00	55-S2	29.90
22	0312 Trimble Cty 1 FGD	2,737	55.00	-11.00	0.88	55-S2	29.50
23	0321 Trimble Cty 2	8,958	55.00	-11.00	2.29	55-S2	47.50
24							
25	316 Misc Plant Equipmt						
26	0112 Cane Run Unit 1	39	45.00	-2.00		45-R2.5	
27	0131 Cane Run Unit 3	12	45.00	-2.00		45-R2.5	
28	0141 Cane Run Unit 4	87	45.00	-2.00	16.79	45-R2.5	4.00
29	0142 Cane Run 4 FGD	6	45.00	-2.00		45-R2.5	
30	0151 Cane Run Unit 5	97	45.00	-2.00	15.39	45-R2.5	4.00
31	0152 Cane Run 5 FGD	47	45.00	-2.00		45-R2.5	
32	0161 Cane Run Unit 6	3,019	45.00	-2.00	13.71	45-R2.5	4.00
33	0162 Cane Run 6 FGD	32	45.00	-2.00		45-R2.5	
34	0211 Mill Creek Unit 1	758	45.00	-8.00	2.51	45-R2.5	16.70
35	0221 Mill Creek Unit 2	160	45.00	-8.00	1.76	45-R2.5	18.60
36	0231 Mill Creek Unit 3	359	45.00	-8.00	1.22	45-R2.5	23.90
37	0241 Mill Creek Unit 4	8,678	45.00	-8.00	2.71	45-R2.5	26.60
38	0242 Mill Creek 4 FGD	75	45.00	-8.00	2.05	45-R2.5	27.80
39	0311 Trimble Cty 1	2,931	45.00	-11.00	2.47	45-R2.5	28.20
40	0321 Trimble Cty 2	2,489	45.00	-11.00	2.54	45-R2.5	42.70
41							
42	317 Asset Rtiremt Oblg	47,915					
43							
44	Hydraulic Prodctn Plnt						
45	Project 289						
46	0451 - Ohio Falls						
47	330.20 Land						
48	331 Structrs & Imprvmt	5,895	100.00	-3.00	0.47	100-S2	33.70
49	332 Resrvrs Dams Wtrty	13,130	100.00	-3.00	2.62	100-S2.5	33.70
50	333 Wtr Whls Trbns Gen	36,268	100.00	-3.00	2.96	100-S2.5	33.30

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	334 Accessry Elec Eqpt	6,148	80.00	-3.00	2.01	80-S4	33.80
13	335 Misc Pwr Plnt Eqpm	298	80.00	-3.00	2.63	80-S1.5	32.30
14	336 Rds Railrds Bridge	29	80.00	-3.00	2.26	80-S4	19.30
15							
16	Hydraulic Prodctn Plnt						
17	Other Than Proj 289						
18	0450 - Ohio Falls						
19	330.20 Land						
20	331 Structrs & Imprvmt	66	100.00	-3.00	1.46	100-S2	30.00
21	335 Misc Pwr Plnt Eqpm	25	80.00	-3.00	2.81	80-S1.5	31.40
22	336 Rds Railrds Bridge	1	80.00	-3.00	2.26	80-S4	19.30
23	337 Asset Rtiremt Oblg	50					
24							
25	Other Production Plant						
26	340.20 Land	13					
27							
28	341 Strctrs & Imprvmnt						
29	0171 Cane Run GT 11	212	55.00	-2.00	13.86	55-R3	6.40
30	0410 Zorn and River	8	55.00	-3.00		55-R3	
31	0431 Paddys Run Gen 12	64	55.00	-3.00	3.23	55-R3	6.50
32	0432 Paddys Run Gen 13	2,159	55.00	-3.00	3.57	55-R3	19.00
33	0459 Brown CT5	859	55.00	-3.00	3.57	55-R3	19.00
34	0460 Brown CT6	106	55.00	-3.00	4.09	55-R3	17.20
35	0461 Brown CT7	144	55.00	-3.00	4.08	55-R3	17.20
36	0470 Trimble Cty CT5	1,556	55.00	-3.00	3.58	55-R3	20.00
37	0471 Trimble Cty CT6	1,468	55.00	-3.00	3.57	55-R3	20.00
38	0474 Trimble Cty CT7	2,084	55.00	-3.00	3.52	55-R3	22.00
39	0475 Trimble Cty CT8	2,076	55.00	-3.00	3.52	55-R3	22.00
40	0476 Trimble Cty CT9	2,136	55.00	-3.00	3.53	55-R3	22.00
41	0477 Trimble Cty CT10	2,132	55.00	-3.00	3.53	55-R3	22.00
42							
43	342 Fuel Holders Prdcr						
44	0171 Cane Run GT 11	320	45.00	-2.00	14.18	45-R2.5	6.40
45	0410 Zorn and River	23	45.00	-3.00	3.84	45-R2.5	7.50
46	0430 Paddys Run Gen 11	9	45.00	-3.00		45-R2.5	
47	0431 Paddys Run Gen 12	22	45.00	-3.00	4.93	45-R2.5	6.50
48	0432 Paddys Run Gen 13	2,255	45.00	-3.00	3.70	45-R2.5	18.50
49	0459 Brown CT5	847	45.00	-3.00	4.11	45-R2.5	18.50
50	0460 Brown CT6	403	45.00	-3.00	5.40	45-R2.5	16.80

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	0461 Brown CT7	141	45.00	-3.00	8.07	45-R2.5	17.00
13	0470 Trimble Cty CT5	98	45.00	-3.00	3.68	45-R2.5	19.40
14	0471 Trimble Cty CT6	98	45.00	-3.00	3.68	45-R2.5	19.40
15	0473 Trim Cty Pipeline	2,001	45.00	-3.00	3.35	45-R2.5	21.10
16	0474 Trimble Cty CT7	338	45.00	-3.00	3.63	45-R2.5	21.30
17	0475 Trimble Cty CT8	337	45.00	-3.00	3.63	45-R2.5	21.30
18	0476 Trimble Cty CT9	347	45.00	-3.00	3.65	45-R2.5	21.30
19	0477 Trimble Cty CT10	362	45.00	-3.00	3.66	45-R2.5	21.30
20							
21	343 Prime Movers						
22	0432 Paddys Run Gen 13	22,031	30.00	-3.00	4.56	30-R2	16.40
23	0459 Brown CT5	15,935	30.00	-3.00	4.33	30-R2	16.50
24	0460 Brown CT6	20,076	30.00	-3.00	5.99	30-R2	15.20
25	0461 Brown CT7	18,294	30.00	-3.00	5.05	30-R2	15.10
26	0470 Trimble Cty CT5	13,543	30.00	-3.00	4.37	30-R2	17.60
27	0471 Trimble Cty CT6	13,462	30.00	-3.00	4.49	30-R2	17.30
28	0474 Trimble Cty CT7	14,709	30.00	-3.00	4.03	30-R2	18.90
29	0475 Trimble Cty CT8	14,520	30.00	-3.00	4.03	30-R2	18.90
30	0476 Trimble Cty CT9	14,488	30.00	-3.00	4.08	30-R2	18.90
31	0477 Trimble Cty CT10	14,452	30.00	-3.00	4.08	30-R2	18.90
32							
33	344 Generators						
34	0171 Cane Run GT 11	2,910	60.00	-2.00	4.76	60-S3	6.40
35	0410 Zorn and River	1,828	60.00	-3.00		60-S3	
36	0430 Paddys Run Gen 11	1,523	60.00	-3.00		60-S3	
37	0431 Paddys Run Gen 12	3,067	60.00	-3.00		60-S3	
38	0432 Paddys Run Gen 13	5,893	60.00	-3.00	3.26	60-S3	19.40
39	0459 Brown CT5	3,283	60.00	-3.00	3.61	60-S3	19.40
40	0460 Brown CT6	2,441	60.00	-3.00	3.79	60-S3	17.40
41	0461 Brown CT7	2,444	60.00	-3.00	3.84	60-S3	17.40
42	0470 Trimble Cty CT5	1,557	60.00	-3.00	3.50	60-S3	20.40
43	0471 Trimble Cty CT6	1,554	60.00	-3.00	3.50	60-S3	20.40
44	0474 Trimble Cty CT7	1,749	60.00	-3.00	3.46	60-S3	22.40
45	0475 Trimble Cty CT8	1,739	60.00	-3.00	3.46	60-S3	22.40
46	0476 Trimble Cty CT9	1,750	60.00	-3.00	3.47	60-S3	22.40
47	0477 Trimble Cty CT10	1,745	60.00	-3.00	3.47	60-S3	22.40
48							
49	345 Accssry Elec Eqpmt						
50	0171 Cane Run GT 11	144	45.00	-2.00		45-R3	

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	0410 Zorn & River	85	45.00	-3.00		45-R3	
13	0430 Paddys Run Gen 11	573	45.00	-3.00		45-R3	
14	0431 Paddys Run Gen 12	898	45.00	-3.00	13.71	45-R3	6.50
15	0432 Paddys Run Gen 13	2,807	45.00	-3.00	3.60	45-R3	18.70
16	0459 Brown CT5	2,602	45.00	-3.00	3.60	45-R3	18.70
17	0460 Brown CT6	980	45.00	-3.00	3.91	45-R3	16.90
18	0461 Brown CT7	963	45.00	-3.00	3.94	45-R3	16.80
19	0470 Trimble Cty CT5	713	45.00	-3.00	3.70	45-R3	19.70
20	0471 Trimble Cty CT6	1,598	45.00	-3.00	3.81	45-R3	19.70
21	0474 Trimble Cty CT7	1,892	45.00	-3.00	3.56	45-R3	21.60
22	0475 Trimble Cty CT8	1,839	45.00	-3.00	3.56	45-R3	21.60
23	0476 Trimble Cty CT9	1,898	45.00	-3.00	3.57	45-R3	21.60
24	0477 Trimble Cty CT10	4,453	45.00	-3.00	3.73	45-R3	21.60
25							
26	346 Misc Plant Equipmt						
27	0410 Zorn & River	9	50.00	-3.00	13.22	50-S3	7.50
28	0430 Paddys Run Gen 11	9	50.00	-3.00	15.24	50-S3	6.50
29	0432 Paddys Run Gen 13	1,282	50.00	-3.00	3.72	50-S3	19.30
30	0459 Brown CT5	2,396	50.00	-3.00	3.58	50-S3	19.30
31	0460 Brown CT6	22	50.00	-3.00	3.84	50-S3	17.40
32	0461 Brown CT7	23	50.00	-3.00	3.90	50-S3	17.40
33	0470 Trimble Cty CT5	15	50.00	-3.00	3.72	50-S3	20.40
34	0474 Trimble Cty CT7	5	50.00	-3.00	3.50	50-S3	22.30
35	0475 Trimble Cty CT8	5	50.00	-3.00	3.51	50-S3	22.30
36	0476 Trimble Cty CT9	5	50.00	-3.00	3.51	50-S3	22.30
37	0477 Trimble Cty CT10	25	50.00	-3.00	4.17	50-S3	22.40
38							
39	347 Asset Rtiremt Oblg	32					
40							
41	Elec Trnsmsn Plant						
42	350.20 Trnsmsn Lines L	2,296					
43	350.10 Land Rights	8,588	60.00		1.50	60-R3	47.30
44	352.10 Strctr&Imprvmts	6,602	55.00	-5.00	1.74	55-R1.5	47.10
45	353.10 Station Equipmt	141,383	55.00	-10.00	1.38	55-R2.5	40.20
46	354 Towers & Fixtures	40,986	70.00	-50.00	1.72	70-R3	54.60
47	355 Poles & Fixtures	60,619	53.00	-55.00	2.89	53-R2	41.80
48	356 Ovrhead Cndctrs&Dv	48,914	50.00	-40.00	2.50	50-R2	35.20
49	357 Undrground Conduit	2,279	55.00		1.67	55-R3	44.60
50	358 Undrgrnd Cndctrs&D	7,425	35.00	-5.00	2.98	35-R3	22.30

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	359 Asset Rtiremt Oblg	218					
13							
14	Distribution Plant						
15	360.20 Substation Land	4,124					
16	361 Substation Strctrs	6,768	50.00	-10.00	1.61	50-L1.5	40.00
17	362 Substation Eqpm	119,421	50.00	-15.00	2.09	50-R1.5	38.10
18	364 Poles Twrs & Fxtur	159,309	50.00	-70.00	3.39	50-R2.5	35.40
19	365 Ovhd Cndctrs&Dvcs	261,176	50.00	-60.00	2.98	50-R1.5	39.70
20	366 Undrground Conduit	74,750	70.00	-20.00	1.50	70-R4	54.80
21	367 Undrgrnd Cndctrs&D	161,832	55.00	-20.00	1.92	55-R3	45.10
22	368 Line Trnsformr	145,012	45.00	-20.00	2.38	45-R3	31.50
23	369.10 Undrgrnd Srvcs	7,517	45.00	-40.00	3.32	45-R2.5	34.20
24	369.20 Ovrhead Srvcs	22,546	50.00	-100.00	3.59	50-R2	29.70
25	370 Meters	39,276	30.00		2.92	30-R2.5	16.10
26	373.10 Ovrhd St Lightn	38,049	28.00	-25.00	3.97	28-L0.5	22.10
27	373.20 Undrgrd St Lght	49,947	35.00	-30.00	3.44	35-R2	24.80
28	374 Asset Rtiremt Oblg	638					
29							
30	General Plant						
31	392.10 Trnsp Heavy Tr	7,887	14.00		0.60	14-S1.5	13.50
32	392.20 Trnsprtatn Trlr	758	20.00	5.00	6.21	20-S1	8.50
33	394 Tools Shp Grage Eq	5,039	25.00		4.51	25-SQ	14.90
34	396.10 Pwr Op Eqp Smal	2,155	8.00			8-L2	
35	396.20 Pwr Pwr Eqp Oth	196	17.00		7.60	17-L3	10.80
36	397.20 DSM Comm Equip	1,762	10.00		13.14	10-SQ	3.50
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 336 Line No.: 12 Column: e

See footnote data detail on Schedule Page: 114, Line No.: 7, Column: c.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	350,681		350,681	
3	Administrative Charge, Project #289	173,558		173,558	
4					
5	2009 Rate Case - Electric (Aug-10 to Jul-13)		163,236	163,236	163,236
6	2009 Rate Case - Gas (Aug-10 to Jul-13)		93,416	93,416	93,416
7					
8	2012 Rate Case - Electric (Jan-13 to Dec-15)		298,138	298,138	894,413
9	2012 Rate Case - Gas (Jan-13 to Dec-15)		94,935	94,935	284,806
10					
11	2011 Gen Mgmt Audit - Elec (Jan-13 to Dec-15)		30,528	30,528	91,583
12	2011 Gen Mgmt Audit - Gas (Jan-13 to Dec-15)		9,943	9,943	29,825
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46	TOTAL	524,239	690,196	1,214,435	1,557,279

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	350,681					2
Electric	928	173,558					3
							4
Electric	928	163,236		928	163,236		5
Gas	928	93,416		928	93,416		6
							7
Electric	928	298,138	76	928	298,138	596,351	8
Gas	928	94,935	24	928	94,935	189,895	9
							10
Electric	928	30,528		928	30,528	61,055	11
Gas	928	9,943		928	9,943	19,882	12
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		1,214,435	100		690,196	867,183	46

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:
A. Electric R, D & D Performed Internally:
  (1) Generation
    a. hydroelectric
      i. Recreation fish and wildlife
      ii Other hydroelectric
    b. Fossil-fuel steam
    c. Internal combustion or gas turbine
    d. Nuclear
    e. Unconventional generation
    f. Siting and heat rejection
  (2) Transmission
    a. Overhead
    b. Underground
  (3) Distribution
  (4) Regional Transmission and Market Operation
  (5) Environment (other than equipment)
  (6) Other (Classify and include items in excess of $50,000.)
  (7) Total Cost Incurred
B. Electric, R, D & D Performed Externally:
  (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	EPRI (1)	Annual Membership and Annual Research Portfolio
2	EPRI (1)	Annual Membership and Annual Research Portfolio
3	EPRI (1)	Plant Reliability Interest Group
4	EPRI (1)	BSA Power Plant Parameter Derivation Software User's Group
5	EPRI (1)	CF Effluent Guidelines Information Collection and Evaluation
6	EPRI (1)	Tailored Collaboration
7	Kentucky Consortium for Carbon Storage (4)	Amortization of Carbon Storage Project Regulatory Asset
8	University of Kentucky Research Foundation (4)	Amortization of Carbon Capturing Research Regulatory Asset
9	University of Texas at Austin (4)	Tailored Collaboration
10	Georgia Tech Research Corporation (1)	NEETRAC Membership Renewal
11	University of Kentucky (1)	Design Drawings for ClearEdge Fuel Cell
12	Ronald Doades and Company (1)	Annual Participation in Research & Technology Management Forum
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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.
	112,608	107	112,608		1
	1,059,204	930	1,059,204		2
	975	500	975		3
	2,535	510	2,535		4
	12,863	930	12,863		5
	167,066	930	167,066		6
	219,510	930	219,510		7
	97,560	930	97,560		8
	29,250	930	29,250		9
	9,750	930	9,750		10
	1,605	500	1,605		11
	5,655	930	5,655		12
					13
					14
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			1,718,581		16
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	23,264,337		
4	Transmission	2,922,592		
5	Regional Market			
6	Distribution	7,806,010		
7	Customer Accounts	3,731,716		
8	Customer Service and Informational	789,073		
9	Sales			
10	Administrative and General	15,519,000		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	54,032,728		
12	Maintenance			
13	Production	11,012,179		
14	Transmission	357,430		
15	Regional Market			
16	Distribution	2,748,571		
17	Administrative and General	2,222,824		
18	TOTAL Maintenance (Total of lines 13 thru 17)	16,341,004		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	34,276,516		
21	Transmission (Enter Total of lines 4 and 14)	3,280,022		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	10,554,581		
24	Customer Accounts (Transcribe from line 7)	3,731,716		
25	Customer Service and Informational (Transcribe from line 8)	789,073		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	17,741,824		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	70,373,732	17,764,315	88,138,047
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	528,021		
34	Storage, LNG Terminaling and Processing	1,705,065		
35	Transmission	490,754		
36	Distribution	2,972,172		
37	Customer Accounts	3,053,012		
38	Customer Service and Informational	266,102		
39	Sales			
40	Administrative and General	3,780,247		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	12,795,373		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	1,337,658		
47	Transmission	69,093		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	5,130,603		
49	Administrative and General	907,667		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	7,445,021		
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)	528,021		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	3,042,723		
56	Transmission (Lines 35 and 47)	559,847		
57	Distribution (Lines 36 and 48)	8,102,775		
58	Customer Accounts (Line 37)	3,053,012		
59	Customer Service and Informational (Line 38)	266,102		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	4,687,914		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	20,240,394	5,038,137	25,278,531
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	90,614,126	22,802,452	113,416,578
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	9,938,504	8,319,112	18,257,616
69	Gas Plant	5,098,826	4,563,389	9,662,215
70	Other (provide details in footnote):	2,289,051	1,086,356	3,375,407
71	TOTAL Construction (Total of lines 68 thru 70)	17,326,381	13,968,857	31,295,238
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,035,830	567,851	1,603,681
74	Gas Plant	157,332	131,239	288,571
75	Other (provide details in footnote):	198	56	254
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,193,360	699,146	1,892,506
77	Other Accounts (Specify, provide details in footnote):			
78	Accounts Receivable (work done for others)	7,017,252	1,652,001	8,669,253
79	Miscellaneous Deferred Debits	77,369	-183,537	-106,168
80	Certain Civic, Political and Related Activities and Other	446,340	133,250	579,590
81	Accounts Receivable (Non-jurisdictional - Trimble County)	1,726,419	431,196	2,157,615
82				
83				
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94				
95	TOTAL Other Accounts	9,267,380	2,032,910	11,300,290
96	TOTAL SALARIES AND WAGES	118,401,247	39,503,365	157,904,612

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2013/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

(1) See attached sheet, page 356.1.

(2) See attached sheet, page 356.1.

(3) Depreciation - Electric $7,688,535; Gas $3,140,388. Amortization - Electric $5,643,550; Gas $2,305,153.

Common Utility expense accounts are not maintained, but such expenses are allocated to Electric and Gas Departments as follows:

Customer Accounts Expenses (excluding for uncollectable accounts).

Allocated between departments based on average number of customers served by each department for the year ending December 31, 2012.

Customer Service and Informational Expenses.

Allocated between departments based on gross revenues from ultimate consumers by departments for the twelve month period.

Administrative and General Expenses

The administrative and general expenses are allocated on the basis of total direct costs.

(4) The property original cost studies made pursuant to the Uniform System of Accounts included a separate classification for Common Utility Plant. Orders were issued in connection with such studies by Public Service Commission of Kentucky on September 16, 1941, and January 5, 1945, and the Federal Power Commission on December 15, 1944.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2013/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Common Utility Plant (1)
Allocation to Utility Department (2)

Accounts 101 and 106	Electric 71%	Gas 29%	Balance End of Year
Intangible Plant			
301 Organization			$ 83,781
303 Miscellaneous Intangible Plant			77,582,794
Total Intangible Plant			$ 77,666,575
General Plant			
389 Land and Land Rights			$ 1,887,411
390 Structures and Improvements			76,484,107
391 Office and Furniture and Equipment			36,434,691
392 Transportation Equipment			381,792
393 Stores Equipment			1,333,721
394 Tools, Shop and Garage Equipment			3,790,568
396 Power Operated Equipment			249,978
397 Communication Equipment			38,294,714
399 ARO Common Plant			107,438
Total Common Plant			$ 158,964,420
Total Accounts 101 and 106			$ 236,630,995
Account 107			20,480,272
Total Common Utility Plant	$ 182,549,000	$ 74,562,267	$ 257,111,267

Accumulated Provision for Depreciation of Common Utility Plant

Balance at end of year	$ 83,216,023	$ 33,989,643	$ 117,205,666

(1) Common plant consists of land, structures and equipment of a general nature used by all departments not specifically assignable to one department, and includes offices, storerooms, communication, transportation, and work equipment, etc.

(2) Based on estimated usage by departments.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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)	12,006	29,075	63,720	103,047
3	Net Sales (Account 447)	2,408,295	4,246,103	6,497,149	9,466,901
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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45					
46	TOTAL	2,420,301	4,275,178	6,560,869	9,569,948

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 397 Line No.: 2 Column: b

The amount reflects transactions recorded in accordance with LG&E's Power Supply System Agreement with KU, as approved by the KPSC in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. There was no difference between the different calculation methods in the first quarter of 2013 for purchases recorded in accordance with the FERC Order No. 668-A.

Schedule Page: 397 Line No.: 2 Column: c

The amount reflects transactions recorded in accordance with LG&E's Power Supply System Agreement with KU, as approved by the KPSC in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. There was no difference between the different calculation methods in the second quarter of 2013 for purchases recorded in accordance with the FERC Order No. 668-A.

Schedule Page: 397 Line No.: 2 Column: d

The amount reflects transactions recorded in accordance with LG&E's Power Supply System Agreement with KU, as approved by the KPSC in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. There was no difference between the different calculation methods in the third quarter of 2013 for purchases recorded in accordance with the FERC Order No. 668-A.

Schedule Page: 397 Line No.: 2 Column: e

The amount reflects transactions recorded in accordance with LG&E's Power Supply System Agreement with KU, as approved by the KPSC in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. There was no difference between the different calculation methods in the fourth quarter of 2013 for purchases recorded in accordance with the FERC Order No. 668-A.

Schedule Page: 397 Line No.: 3 Column: b

The amount reflects transactions recorded in accordance with LG&E's Power Supply System Agreement with KU, as approved by the KPSC in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. There was no difference between the different calculation methods in the first quarter of 2013 for purchases recorded in accordance with the FERC Order No. 668-A.

Schedule Page: 397 Line No.: 3 Column: c

The amount reflects transactions recorded in accordance with LG&E's Power Supply System Agreement with KU, as approved by the KPSC in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. There was no difference between the different calculation methods in the second quarter of 2013 for purchases recorded in accordance with the FERC Order No. 668-A.

Schedule Page: 397 Line No.: 3 Column: d

The amount reflects transactions recorded in accordance with LG&E's Power Supply System Agreement with KU, as approved by the KPSC in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. There was no difference between the different calculation methods in the third quarter of 2013 for purchases recorded in accordance with the FERC Order No. 668-A.

Schedule Page: 397 Line No.: 3 Column: e

The amount reflects transactions recorded in accordance with LG&E's Power Supply System Agreement with KU, as approved by the KPSC in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. There was no difference between the different calculation methods in the fourth quarter of 2013 for purchases recorded in accordance with the FERC Order No. 668-A.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	237,272	MWH	94,806	3,505,999	MWH	352,089
2	Reactive Supply and Voltage	237,272	MWH	46,457	3,505,999	MWH	291,753
3	Regulation and Frequency Response				3,505,999	MWH	103,695
4	Energy Imbalance						
5	Operating Reserve - Spinning				3,505,999	MWH	150,029
6	Operating Reserve - Supplement				3,505,999	MWH	142,857
7	Other			1,202			
8	Total (Lines 1 thru 7)	474,544		142,465	17,529,995		1,040,423

Name of Respondent Louisville Gas and Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2013/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

This amount consists of Black Start services.

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Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	2,070	22	8	1,754	209	107			
2	February	2,032	1	8	1,695	230	107			
3	March	1,935	22	7	1,623	205	107			
4	Total for Quarter 1	6,037			5,072	644	321			
5	April	1,649	3	7	1,397	145	107			
6	May	2,491	30	16	2,182	202	107			
7	June	2,773	12	16	2,441	225	107			
8	Total for Quarter 2	6,913			6,020	572	321			
9	July	2,934	17	15	2,466	236	107		125	
10	August	2,856	28	17	2,514	235	107			
11	September	2,821	10	15	2,515	199	107			
12	Total for Quarter 3	8,611			7,495	670	321		125	
13	October	2,249	4	16	1,989	153	107			
14	November	1,940	27	19	1,639	194	107			
15	December	2,069	12	9	1,743	219	107			
16	Total for Quarter 4	6,258			5,371	566	321			
17	Total Year to Date/Year	27,819			23,958	2,452	1,284		125	

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	13,977,112
4	Nuclear	
5	Hydro-Conventional	193,332
6	Hydro-Pumped Storage	
7	Other	175,887
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	14,346,331
10	Purchases	917,707
11	Power Exchanges:	
12	Received	4,051
13	Delivered	240,510
14	Net Exchanges (Line 12 minus line 13)	-236,459
15	Transmission For Other (Wheeling)	
16	Received	3,505,999
17	Delivered	3,469,569
18	Net Transmission for Other (Line 16 minus line 17)	36,430
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	15,064,009

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	11,698,975
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,779,341
25	Energy Furnished Without Charge	1,562
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	22,338
27	Total Energy Losses	561,793
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	15,064,009

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	1,409,828	394,052	1,784	22	2000
30	February	1,252,564	351,624	1,715	1	1100
31	March	1,173,997	203,964	1,631	21	800
32	April	1,085,558	216,588	1,679	10	1700
33	May	1,256,998	242,262	2,198	30	1500
34	June	1,307,941	169,358	2,441	12	1600
35	July	1,401,538	200,091	2,494	18	1400
36	August	1,418,949	166,184	2,514	28	1700
37	September	1,188,975	140,084	2,529	10	1600
38	October	1,022,771	99,769	1,989	4	1600
39	November	1,159,654	268,039	1,639	27	1900
40	December	1,385,236	327,326	1,762	10	1900
41	TOTAL	15,064,009	2,779,341			

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 401 Line No.: 29 Column: b

The value reported in the first quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 1,503,076 MWH.

Schedule Page: 401 Line No.: 30 Column: b

The value reported in the first quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 1,350,995 MWH.

Schedule Page: 401 Line No.: 31 Column: b

The value reported in the first quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 1,269,693 MWH.

Schedule Page: 401 Line No.: 32 Column: b

The value reported in the second quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 1,177,337 MWH.

Schedule Page: 401 Line No.: 33 Column: b

The value reported in the second quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 1,347,672 MWH.

Schedule Page: 401 Line No.: 34 Column: b

The value reported in the second quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 1,417,167 MWH.

Schedule Page: 401 Line No.: 35 Column: b

The value reported in the third quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 1,510,912 MWH.

Schedule Page: 401 Line No.: 36 Column: b

The value reported in the third quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 1,536,583 MWH.

Schedule Page: 401 Line No.: 37 Column: b

The value reported in the third quarter was revised due to the inclusion of IMEA and IMPA generation. The previously reported balance was 1,297,756 MWH.

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Mill Creek* (b)			Plant Name: *Cane Run* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1972			1954		
4	Year Last Unit was Installed	1982			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1717.00			645.00		
6	Net Peak Demand on Plant - MW (60 minutes)	1472			569		
7	Plant Hours Connected to Load	7170			7005		
8	Net Continuous Plant Capability (Megawatts)	1472			563		
9	When Not Limited by Condenser Water	1472			563		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	239			130		
12	Net Generation, Exclusive of Plant Use - KWh	8286913000			2556296000		
13	Cost of Plant: Land and Land Rights	1919832			1320200		
14	Structures and Improvements	127752287			45289477		
15	Equipment Costs	1012695173			293518109		
16	Asset Retirement Costs	18366438			22516947		
17	Total Cost	1160733730			362644733		
18	Cost per KW of Installed Capacity (line 17/5) Including	676.0243			562.2399		
19	Production Expenses: Oper, Supv, & Engr	1846326			863685		
20	Fuel	218066365			64961872		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	14293721			17182368		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	72676			73503		
26	Misc Steam (or Nuclear) Power Expenses	8135706			6467770		
27	Rents	44500			8500		
28	Allowances	77172			37796		
29	Maintenance Supervision and Engineering	1085582			1260675		
30	Maintenance of Structures	952662			610157		
31	Maintenance of Boiler (or reactor) Plant	27552410			7363904		
32	Maintenance of Electric Plant	6766029			2518866		
33	Maintenance of Misc Steam (or Nuclear) Plant	666146			661733		
34	Total Production Expenses	279559295			102010829		
35	Expenses per Net KWh	0.0337			0.0399		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Gas		Coal	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	tons	mcf		tons	mcf	
38	Quantity (Units) of Fuel Burned	3787549	464041	0	1269263	117214	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11614	1025	0	11082	1025	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	56.100	9.981	0.000	49.330	19.091	0.000
41	Average Cost of Fuel per Unit Burned	56.350	9.981	0.000	49.413	19.091	0.000
42	Average Cost of Fuel Burned per Million BTU	2.426	9.738	0.000	2.229	18.625	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.026	0.000	0.000	0.025	0.000	0.000
44	Average BTU per KWh Net Generation	10617.000	0.000	0.000	11005.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Trimble County* (d)	Plant Name: *Cane Run CT* (e)	Plant Name: *Paddy's Run CT* (f)	Line No.
Steam	Combustion Turbine	Combustion Turbine	1
Conventional	Conventional	Conventional	2
1990	1968	1968	3
2011	1968	2001	4
544.00	16.00	143.00	5
662	10	94	6
6532	36	75	7
487	14	113	8
487	14	113	9
0	0	0	10
171	0	0	11
4268436000	180000	15310000	12
3562369	0	0	13
129291465	211518	2222812	14
587574102	3372882	40369647	15
7031831	0	0	16
727459767	3584400	42592459	17
1337.2422	224.0250	297.8494	18
1184253	0	0	19
109099722	120488	1584130	20
0	0	0	21
3448507	0	0	22
0	0	0	23
0	0	0	24
949788	538	7265	25
5172893	0	0	26
1874	0	7380	27
25995	0	0	28
702613	0	1253	29
787628	9589	3687	30
11041398	0	0	31
1574399	25262	309381	32
481201	0	0	33
134470271	155877	1913096	34
0.0315	0.8660	0.1250	35

(d)			(e)			(f)			Line No.
Coal	Oil		Gas	Oil		Gas			36
tons	barrels		mcf	barrels		mcf			37
1983101	17803	0	7529	0	0	178692	0	0	38
11278	3333	0	1025	0	0	1025	0	0	39
53.610	100.177	0.000	16.003	0.000	0.000	8.865	0.000	0.000	40
39.326	100.177	0.000	16.003	0.000	0.000	8.865	0.000	0.000	41
1.743	17.037	0.000	15.613	0.000	0.000	8.649	0.000	0.000	42
0.018	0.000	0.000	0.669	0.000	0.000	0.103	0.000	0.000	43
10479.000	0.000	0.000	42872.000	0.000	0.000	11963.000	0.000	0.000	44

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Zorn CT* (b)			Plant Name: *Brown CT* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combustion Turbine			Combustion Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1969			1999		
4	Year Last Unit was Installed	1969			2001		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	18.00			200.00		
6	Net Peak Demand on Plant - MW (60 minutes)	14			121		
7	Plant Hours Connected to Load	29			179		
8	Net Continuous Plant Capability (Megawatts)	14			180		
9	When Not Limited by Condenser Water	14			180		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	203000			37198000		
13	Cost of Plant: Land and Land Rights	0			5015		
14	Structures and Improvements	8241			1108873		
15	Equipment Costs	1945203			70849350		
16	Asset Retirement Costs	32135			0		
17	Total Cost	1985579			71963238		
18	Cost per KW of Installed Capacity (line 17/5) Including	110.3099			359.8162		
19	Production Expenses: Oper, Supv, & Engr	0			55723		
20	Fuel	22691			1973659		
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	6963			23813		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			6995		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			19358		
30	Maintenance of Structures	0			86209		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	14491			216716		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	44145			2382473		
35	Expenses per Net KWh	0.2175			0.0640		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	mcf			mcf	barrels	
38	Quantity (Units) of Fuel Burned	5334	0	0	469121	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	985	0	0	1025	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.254	0.000	0.000	4.207	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.254	0.000	0.000	4.207	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.318	0.000	0.000	4.105	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.112	0.000	0.000	0.053	0.000	0.000
44	Average BTU per KWh Net Generation	25887.000	0.000	0.000	12927.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Trimble County CT* (d)			Plant Name: (e)			Plant Name: (f)			Line No.
Combustion Turbine									1
Conventional									2
2002									3
2004									4
410.00			0.00			0.00			5
339			0			0			6
636			0			0			7
323			0			0			8
323			0			0			9
0			0			0			10
0			0			0			11
122996000			0			0			12
8133			0			0			13
11452996			0			0			14
111299099			0			0			15
0			0			0			16
122760228			0			0			17
299.4152			0			0			18
0			0			0			19
12304194			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
193381			0			0			25
0			0			0			26
572			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
325214			0			0			32
0			0			0			33
12823361			0			0			34
0.1043			0.0000			0.0000			35
Gas									36
mcf									37
1535008	0	0	0	0	0	0	0	0	38
1025	0	0	0	0	0	0	0	0	39
4.699	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
4.699	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
6.536	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.084	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
12792.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 403 Line No.: -1 Column: d

Partnership Expenses included in Column f:

Line No.: 19	Production Expenses: Oper, Supv, & Engr	$ (296,065)
Line No.: 20	Fuel	(29,098,072)
Line No.: 22	Steam Expenses	(892,939)
Line No.: 25	Electric Expenses	(237,447)
Line No.: 26	Misc Steam Power Expenses	(1,293,225)
Line No.: 27	Rents	(468)
Line No.: 28	Allowances	(6,499)
Line No.: 29	Maintenance Supervision and Engineering	(175,654)
Line No.: 30	Maintenance of Structures	(196,907)
Line No.: 31	Maintenance of Boiler Plant	(2,778,581)
Line No.: 32	Maintenance of Electric Plant	(393,601)
Line No.: 33	Maintenance of Misc Steam Plant	(120,301)
Line No.: 34	Total Production Expenses	$(35,489,759)

Total Power Production Expenses per Schedule Page: 402-403, Sum of Line No.: 34, Column: b-f	$533,359,347
IMEA-IMPA Partnership Expenses	(35,489,759)
Total Power Production Expenses per Schedule Page: 320-321, Sum of Line No.: 21 & 74, Column: b	$497,869,588

Schedule Page: 403 Line No.: 1 Column: d

The Nameplate Rating for Trimble County Steam Unit 1 represents 75% ownership of the 566 MW unit. The Nameplate Rating for Trimble County Steam Unit 2 represents 14.25% ownership of the 629 MW unit. The remaining percentages of Units 1 and 2 are owned by KU, IMEA and IMPA.

Schedule Page: 403 Line No.: 5 Column: f

The Nameplate Rating for Paddy's Run represents 100% ownership of unit 11, a 16 MW unit, and unit 12, a 33 MW unit, and 53% ownership of unit 13, a 178 MW unit, for LG&E. The remaining percentage of unit 13 is owned by KU.

Schedule Page: 403 Line No.: 11 Column: e

Employees at the Cane Run Plant include those assigned to the steam plant and the Cane Run CT site and are reflected in the Cane Run Steam Plant statistics.

Schedule Page: 403 Line No.: 11 Column: f

No production/operation employees are directly assigned to Paddy's Run turbines. Employees from the Cane Run Plant operate and maintain the Paddy's Run turbines.

Schedule Page: 402.1 Line No.: 5 Column: c

The Nameplate Rating for Brown CT represents 53% ownership of unit 5, a 123 MW unit, and 38% ownership of units 6 and 7, which are 177 MW each, for LG&E. The remaining percentages of units 5, 6 and 7 are owned by KU.

Schedule Page: 403.1 Line No.: 5 Column: d

The Nameplate Rating for Trimble County CT represents 29% ownership of units 5 and 6, and 37% ownership of units 7, 8, 9 and 10 for LG&E. The remaining percentages for units 5, 6, 7, 8, 9 and 10 are owned by KU. Total Nameplate Ratings for these units are 199 MW per unit.

Schedule Page: 402.1 Line No.: 11 Column: b

No production/operation employees are directly assigned to the Zorn station. Employees from the Cane Run Plant maintain the Zorn station. Zorn station is peak load only and is automatically operated.

Schedule Page: 402.1 Line No.: 11 Column: c

Employees at the Brown plant include those assigned to the steam plant and the Brown CT site and are reflected in the Brown steam plant statistics.

Schedule Page: 403.1 Line No.: 11 Column: d

Employees at the Trimble County plant include those assigned to the steam plant and the

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FOOTNOTE DATA

Trimble County CT site and are reflected in the Trimble County steam plant statistics.

Schedule Page: 402.1 Line No.: 13 Column: c

Purchase of Brown CT Joint Use Land from KU. Units 5, 6 and 7. Inflated for survey costs.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 289 Plant Name: Ohio Falls (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1928	
4	Year Last Unit was Installed	1928	
5	Total installed cap (Gen name plate Rating in MW)	88.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	74	0
7	Plant Hours Connect to Load	6,761	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	54	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	8	0
12	Net Generation, Exclusive of Plant Use - Kwh	193,332,000	0
13	Cost of Plant		
14	Land and Land Rights	6	0
15	Structures and Improvements	5,960,586	0
16	Reservoirs, Dams, and Waterways	13,130,436	0
17	Equipment Costs	42,739,002	0
18	Roads, Railroads, and Bridges	29,931	0
19	Asset Retirement Costs	50,210	0
20	TOTAL cost (Total of 14 thru 19)	61,910,171	0
21	Cost per KW of Installed Capacity (line 20 / 5)	703.5247	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	116,451	0
24	Water for Power	38,914	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	250,173	0
27	Misc Hydraulic Power Generation Expenses	120,692	0
28	Rents	341,326	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	282,571	0
31	Maintenance of Reservoirs, Dams, and Waterways	552,874	0
32	Maintenance of Electric Plant	318,172	0
33	Maintenance of Misc Hydraulic Plant	2,040	0
34	Total Production Expenses (total 23 thru 33)	2,023,213	0
35	Expenses per net KWh	0.0105	0.0000

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Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Mill Creek Sub	Paddy's West Sub	345.00	345.00	ST	14.54		2
2	Paddy's West Sub	Northside Sub	345.00	345.00	ST, SP	14.52		1
3	Trimble County Sub	Clifty Creek Sub	345.00	345.00	ST,WP	12.35		2
4	Blue Lick Sub	Middletown Sub	345.00	345.00	ST	0.12	19.22	1
5	Buckner	Wises Landing	345.00	345.00	ST,SP	0.32	13.11	1
6	Middletown	Buckner	345.00	345.00	ST,SP	0.16	14.13	1
7	Middletown Sub	Trimble County Sub	345.00	345.00	ST	27.96		1
8	Mill Creek Sub	Blue Lick Sub	345.00	345.00	ST	0.24	11.80	1
9	Mill Creek Sub	Middletown Sub	345.00	345.00	ST	31.36		1
10	Paddy's Run Sub	T.V.A. Tower	161.00	161.00	ST	66.16	50.25	2
11	Appl Park Switching Station	Middletown Sub	138.00	138.00	ST	0.08	12.56	1
12	Appl Park Switching Station	Ethel Sub	138.00	138.00	WP, ST	1.95		1
13	Ashbottom Sub	Appl Park Switching Station	138.00	138.00	ST	4.61	1.30	1
14	Grade Lane	Fern Valley Sub	138.00	138.00	ST,SP	2.79		1
15	Ashbottom	Grade Lane	138.00	138.00	ST,SP	0.92		1
16	Ashbottom Sub	Manslick Sub	138.00	138.00	WP, ST	3.43		1
17	Ashby Sub	Pleasure Ridge Park Sub	138.00	138.00	WP,SP,CP	2.82		1
18	Beargrass Sub	Lyndon South Sub	138.00	138.00	ST	0.10	7.33	1
19	Beargrass Sub	Middletown Sub	138.00	138.00	ST	9.06	5.53	2
20	Beargrass Sub	Northside Sub	138.00	138.00	ST,SP	6.37		1
21	Beargrass Sub	Northside Sub	138.00	138.00	ST	0.23	6.11	1
22	Breckenridge Sub	Hurstbourne Sub	138.00	138.00	WP, SP,CP	3.89	0.17	1
23	Campground	Cane Run Switching Station	138.00	138.00	ST	3.08	3.29	2
24	Canal Sub	Waterside West	138.00	138.00	ST	0.23	0.87	1
25	Cane Run Switching Station	Ashbottom Sub	138.00	138.00	ST	9.64	7.87	3
26	Cane Run	Cane Run Switching Station	138.00	138.00	ST,WP	5.10		2
27	Cane Run	Cane Run Switching Station	138.00	138.00	ST ,WP	0.46	2.23	2
28	Cane Run	Cane Run Switching Station	138.00	138.00	ST	2.56		1
29	Cane Run	Cane Run Switching Station	138.00	138.00	ST	0.26	2.33	1
30	Cane Run Switching Station	International	138.00	138.00	ST,SP,WP	1.34	1.48	1
31	Centerfield Sub	Trimble County Sub	138.00	138.00	WP, ST	15.08	0.67	1
32	Dixie Sub	Algonquin Sub	138.00	138.00	WP,SP	0.80		1
33	Ethel Sub	Breckenridge Sub	138.00	138.00	WP, ST,SP	3.90		1
34	Fern Valley Sub	Okolona Sub	138.00	138.00	WP, SP	1.40		1
35	Fern Valley Sub	Watterson Sub	138.00	138.00	ST	3.92	1.36	1
36					TOTAL	675.37	241.11	84

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 mcm	113,337	3,237,740	3,351,077					1
1024.5 mcm	102,753	4,300,422	4,403,175					2
954 mcm		3,200,641	3,200,641					3
954 mcm		807,000	807,000					4
954 mcm		2,990,335	2,990,335					5
954 mcm		2,660,313	2,660,313					6
954 mcm	479,907	8,067,643	8,547,550					7
954 mcm		655,355	655,355					8
954 mcm	314,954	4,728,747	5,043,701					9
500 mcm	98,666	2,402,329	2,500,995					10
795 mcm	102,525	928,157	1,030,682					11
795 mcm	862	346,118	346,980					12
795 mcm	42,502	490,157	532,659					13
795 mcm		300,055	300,055					14
795 mcm		186,861	186,861					15
795 mcm		568,452	568,452					16
1272 mcm		1,021,519	1,021,519					17
795 mcm		121,582	121,582					18
795 mcm	159,406	1,282,428	1,441,834					19
1024.5 mcm	67,983	2,284,633	2,352,616					20
1024.5 mcm	6,427	527,124	533,551					21
1272 mcm	15,419	1,425,739	1,441,158					22
795 mcm	8,216	227,384	235,600					23
795 mcm		258,996	258,996					24
795 mcm	38,205	1,374,476	1,412,681					25
795 mcm	18,788	408,209	426,997					26
795 mcm		191,740	191,740					27
954 mcm		156,147	156,147					28
954 mcm		112,910	112,910					29
795 mcm		574,206	574,206					30
795 mcm	85,784	1,212,183	1,297,967					31
795 mcm	1,446	331,415	332,861					32
1272 mcm	27,072	1,179,516	1,206,588					33
1272 mcm		418,533	418,533					34
795 mcm	2,054	57,683	59,737					35
	9,343,438	159,266,460	168,609,898	209,101	1,259,237	30,038	1,498,376	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Hurstbourne Sub	Bluegrass Sub	138.00	138.00	SP,WP	2.02		1
2	Knob Creek Sub	Tip Top Sub	138.00	138.00	WP,ST,CP	11.79		1
3	Lyndon South Sub	Middletown Sub	138.00	138.00	ST,SP	5.58		1
4	Magazine Sub	Hancock Sub	138.00	138.00	SP, WP	2.38	0.04	1
5	Magazine Sub	Waterside West	138.00	138.00	ST, SP, WP	3.38		1
6	Manslick Sub	Mill Creek Sub	138.00	138.00	WP, ST	10.52		1
7	Middletown Sub	Centerfield Sub	138.00	138.00	WP, ST	12.26		1
8	Mill Creek Sub	Ashby Sub	138.00	138.00	WP, SP	5.56		1
9	Mill Creek Sub	Knob Creek Sub	138.00	138.00	WP, ST	2.80	3.59	1
10	Mill Creek Sub	Kosmosdale Prim. Meter Stn.	138.00	138.00	WP, ST	1.27	0.44	2
11	Mud Lane Sub	Blue Lick Sub	138.00	138.00	SP,WP	5.45		1
12	Okolona Sub	Mud Lane Sub	138.00	138.00	WP, ST	3.85	0.18	1
13	Paddy's Run Sub	Campground	138.00	138.00	ST	0.45		1
14	Paddy's Run Sub	Dixie Sub	138.00	138.00	WP,SP	3.58		1
15	Paddy's Run Sub	Ohio Falls Sub	138.00	138.00	ST	12.41	0.39	3
16	Paddy's Run Sub	Paddy's West Sub	138.00	138.00	ST	0.69	0.12	2
17	Plainview Sub	Hurstbourne Sub	138.00	138.00	WP, SP	2.18		1
18	Paddy's West Sub	PSI Connection Gallagher	138.00	138.00	SP	0.42		1
19	Northside Sub	Clifty Creek Sub	138.00	138.00	ST,WP	32.54		1
20	Northside Sub	Tower No. 43 at P.S.I.						
21		Connection	138.00	138.00	ST	0.19	0.04	1
22	Clifty Creek Sub	Tower No.220 Connection						
23		with CG&E Co.	138.00	138.00	ST	4.24	2.50	1
24	Watterson Sub	Middletown Sub	138.00	138.00	ST,WP	7.20	0.22	1
25	Tip Top Sub	Cloverport Sub	138.00	138.00	WP,SP,ST	32.81	2.74	
26	Waterside West	Beargrass Sub	138.00	138.00	ST,SP	2.08		2
27	Waterside West	Beargrass Sub	138.00	138.00	SP	0.25	1.81	1
28	Mill Creek Sub	Cane Run Sub	138.00	138.00	ST,SP	1.19	10.12	1
29	Mill Creek	East Fort Knox	345.00	345.00	HF,ST	6.89		1
30	Middletown	Old Henry	138.00	138.00	ST	4.03		1
31	Old Henry	Collins	138.00	138.00	SP	3.22	0.29	1
32	Trimble County	Speed	345.00	345.00	ST,SP	2.48		1
33	Trimble County	Ghent	345.00	345.00	ST,SP	0.04	2.44	1
34	Overhead Lines under							
35	132KV		69.00	69.00	WP,ST	233.15	54.58	
36					TOTAL	675.37	241.11	84

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 mcm	37,300	1,164,786	1,202,086					1
636 mcm	7,955	1,001,949	1,009,904					2
795 mcm	35,941	591,430	627,371					3
1272 mcm		1,499,878	1,499,878					4
795 mcm	2,600	1,232,065	1,234,665					5
636 mcm	16,570	1,481,079	1,497,649					6
795 mcm	42,761	880,596	923,357					7
1272 mcm	528	1,914,207	1,914,735					8
636 mcm	10,855	411,925	422,780					9
840.2 mcm		743,213	743,213					10
840.2 mcm	46,432	2,601,255	2,647,687					11
1272 mcm	79,825	1,150,041	1,229,866					12
795 mcm	1,455	64,918	66,373					13
795 mcm	27,351	814,401	841,752					14
300 mcm	81,226	918,510	999,736					15
954 mcm	2,763	421,996	424,759					16
1272 mcm	3,591	751,157	754,748					17
954 mcm		219,011	219,011					18
336.4 mcm	73,852	1,491,551	1,565,403					19
								20
954 mcm		45,884	45,884					21
								22
336.4 mcm	22,743	1,003,973	1,026,716					23
840.2 mcm		361,979	361,979					24
397.5 mcm	48,020	2,118,612	2,166,632					25
795 mcm	17,950	446,517	464,467					26
795 mcm		258,350	258,350					27
954 mcm	20,979	683,637	704,616					28
954 mcm	941,552	8,321,901	9,263,453					29
954 mcm		3,435,988	3,435,988					30
954 mcm	10,100	416,299	426,399					31
954 mcm	188,845	15,468,099	15,656,944					32
954 mcm	389,275	1,357,164	1,746,439					33
								34
Various	5,546,663	48,212,434	53,759,097					35
	9,343,438	159,266,460	168,609,898	209,101	1,259,237	30,038	1,498,376	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Ashbottom Sub	Grade Lane Sub	138.00	138.00	Undg. (26)	0.58		1
2	Waterside West	Canal Sub	138.00	138.00	Undg. (26)	0.75		1
3	Magazine Sub	Waterside West	138.00	138.00	Undg. (26)	0.75		1
4	Waterside West	Beargrass Sub	138.00	138.00	Undg. (26)	0.93		1
5	Waterside West	Beargrass Sub	138.00	138.00	Undg. (26)	0.93		1
6	Underground Lines under							
7	132KV		69.00	69.00	Undg. (26)	2.78		
8								
9								
10								
11								
12								
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27								
28								
29								
30								
31								
32								
33								
34	Exp Applicable to All Lines							
35								
36					TOTAL	675.37	241.11	84

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1500 Kcmil cu		1,042,460	1,042,460					1
1750 mcm ho		584,760	584,760					2
1500 mcm ho		584,626	584,626					3
1500 mcm cu		1,659,275	1,659,275					4
1500 mcm ho		1,465,974	1,465,974					5
								6
Various		3,407,812	3,407,812					7
								8
								9
								10
								11
								12
								13
								14
								15
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								29
								30
								31
								32
								33
				209,101	1,259,237	30,038	1,498,376	34
								35
	9,343,438	159,266,460	168,609,898	209,101	1,259,237	30,038	1,498,376	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Aiken	Transmission*	69.00		
2	Algonquin	Transmission*	138.00	69.00	13.80
3	Appliance Park	Transmission*	138.00		
4	Ashbottom	Transmission*	138.00	69.00	13.80
5	Beargrass	Transmission*	138.00	69.00	13.80
6	Beargrass Pumping	Transmission*	69.00		
7	Blue Lick, Brooks, KY	Transmission*	345.00	138.00	
8	Blue Lick, Brooks, KY	Transmission*	345.00	161.00	
9	Blue Lick, Brooks, KY	Transmission*	138.00	69.00	13.80
10	Breckinridge	Transmission*	138.00	69.00	13.20
11	Canal	Transmission*	136.80	66.00	14.00
12	Cane Run Switching	Transmission*	138.00	69.00	13.80
13	Centerfield	Transmission*	138.00	69.00	13.80
14	Clay	Transmission*	69.00		
15	Clifton	Transmission*	69.00		
16	Cloverport	Transmission*	138.00		
17	Collins	Transmission*	138.00	69.00	
18	Eastwood	Transmission*	69.00		
19	Ethel	Transmission*	138.00	69.00	13.80
20	Farnsley	Transmission*	69.00		
21	Fern Valley	Transmission*	138.00	69.00	13.80
22	Ford	Transmission*	69.00		
23	Grady	Transmission*	69.00		
24	Hancock	Transmission*	138.00	69.00	13.80
25	Harrods Creek	Transmission*	69.00		
26	Lyndon	Transmission*	69.00		
27	Lyndon South, Lyndon, KY	Transmission*	138.00	69.00	13.80
28	Madison	Transmission*	69.00		
29	Middletown, Middletown, KY	Transmission*	345.00	138.00	
30	Middletown, Middletown, KY	Transmission*	138.00	69.00	
31	Middletown, Middletown, KY	Transmission*	138.00	69.00	13.80
32	Mill Creek, Kosmosdale, KY	Transmission*	345.00	138.00	13.80
33	Mill Creek, Kosmosdale, KY	Transmission*	138.00	69.00	13.80
34	Mill Creek, Kosmosdale, KY	Transmission*	138.00	69.00	14.00
35	Mud Lane	Transmission*	138.00	69.00	13.80
36	Northside, Jeffersonville, IN	Transmission*	345.00	138.00	13.80
37	Oxmoor	Transmission*	69.00		
38	Paddy's Run	Transmission*	161.00	138.00	
39	Paddy's Run	Transmission*	138.00	69.00	14.00
40	Paddy's West - IN	Transmission*	345.00	138.00	13.80

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
			NONE			1
140	1		NONE			2
			NONE			3
224	2		NONE			4
185	1		NONE			5
			NONE			6
448	1		NONE			7
240	1		NONE			8
112	1		NONE			9
112	1		NONE			10
93	1		NONE			11
224	2		NONE			12
140	1		NONE			13
			NONE			14
			NONE			15
			NONE			16
149	1		NONE			17
			NONE			18
140	1		NONE			19
			NONE			20
80	2		NONE			21
			NONE			22
			NONE			23
140	1		NONE			24
			NONE			25
			NONE			26
140	1		NONE			27
			NONE			28
1344	3		NONE			29
150	1		NONE			30
298	2		NONE			31
672	2		NONE			32
40	1		NONE			33
40	1		NONE			34
140	1		NONE			35
448	1		NONE			36
			NONE			37
200	1		NONE			38
187	1		NONE			39
448	1		NONE			40

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	Seminole	Transmission*	69.00		
2	Shively	Transmission*	69.00		
3	Smyrna	Transmission*	69.00		
4	Taylor	Transmission*	69.00		
5	Tip Top, KY	Transmission*	135.00	66.00	14.00
6	Tip Top, KY	Transmission*	135.00	66.00	37.00
7	Trimble County CT	Transmission*	345.00		
8	Trimble County	Transmission*	345.00	138.00	
9	Waterside West	Transmission*	138.00		
10	Watterson	Transmission*	138.00	69.00	13.80
11	Worthington	Transmission*	69.00		
12	Total Transmission		7536.80	2636.00	340.80
13					
14	Aiken	Distribution*	69.00	12.47	
15	Algonquin	Distribution*	69.00	13.80	
16	Ashbottom	Distribution*	138.00	13.80	
17	Ashby	Distribution*	138.00	12.47	
18	Bishop	Distribution*	69.00	12.47	
19	Bluegrass	Distribution*	138.00	12.47	
20	Brandenburg, near Brandenburg, KY	Distribution*	69.00	12.47	
21	Breckenridge	Distribution*	69.00	13.80	
22	Breckenridge	Distribution*	69.00	12.47	
23	Campground	Distribution*	138.00	13.80	
24	Canal	Distribution*	69.00	13.80	
25	Cane Run	Distribution*	69.00	13.80	
26	Centerfield	Distribution*	138.00	12.47	
27	Clay	Distribution*	69.00	13.80	
28	Clifton	Distribution*	69.00	13.80	
29	Clifton	Distribution*	69.00	12.47	
30	Collins	Distribution*	69.00	12.47	
31	Conestoga	Distribution*	69.00	12.47	
32	Crestwood, Crestwood, KY	Distribution*	69.00	12.47	
33	Crop	Distribution*	13.80	4.16	
34	Dahila	Distribution*	69.00	12.47	
35	Del Park	Distribution*	69.00	13.80	
36	Dixie	Distribution*	138.00	12.47	
37	Eastwood West	Distribution*	69.00	12.47	
38	Ethel	Distribution*	69.00	13.80	
39	Ethel	Distribution*	69.00	12.47	
40	Fairmount	Distribution*	69.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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
34	1		NONE			5
45	1		NONE			6
			NONE			7
448	2		NONE			8
			NONE			9
152	2		NONE			10
			NONE			11
7213	39					12
						13
73	2		NONE			14
101	3		Ground Transformer	4	12	15
95	2		Ground Transformer	2	10	16
56	2		NONE			17
56	2		NONE			18
90	2		NONE			19
11	1		NONE			20
40	2		Ground Transformer	2	5	21
84	3		NONE			22
45	1		Ground Transformer	1	5	23
60	2		Ground Transformer	2	8	24
120	2		Ground Transformer	9	60	25
45	1		NONE			26
50	2		Ground Transformer	2	10	27
20	1		Ground Transformer	2	9	28
56	2		NONE			29
56	2		NONE			30
28	1		NONE			31
56	2		NONE			32
12	2		NONE			33
56	2		NONE			34
45	1		Ground Transformer	1	5	35
45	1		NONE			36
45	1		NONE			37
25	1		Ground Transformer	1	4	38
56	2		NONE			39
73	2		NONE			40

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	Farnsley Shively, KY	Distribution*	69.00	12.47	
2	Fern Valley	Distribution*	138.00	13.80	
3	Fern Valley	Distribution*	138.00	12.47	
4	Floyd	Distribution*	69.00	13.80	
5	Ford Truck Plant	Distribution*	69.00	12.47	
6	Frey's Hill	Distribution*	69.00	12.47	
7	Grade Lane	Distribution*	138.00	13.80	
8	Grady	Distribution*	69.00	13.80	
9	Hancock	Distribution*	138.00	12.47	
10	Harmony Landing, near Goshen, KY	Distribution*	69.00	12.47	
11	Harrod's Creek	Distribution*	69.00	12.47	
12	Herman - Class B	Distribution*	13.80	4.16	
13	Highland #1	Distribution*	69.00	12.47	
14	Highland	Distribution*	69.00	13.80	
15	Hillcrest	Distribution*	69.00	12.47	
16	Hillcrest	Distribution*	69.00	13.80	
17	Hurstbourne, Jeffersontown, KY	Distribution*	138.00	12.47	
18	International	Distribution*	138.00	12.47	
19	Jeffersontown	Distribution*	69.00	12.47	
20	Kenwood	Distribution*	69.00	12.47	
21	Knob Creek, near Shepherdsville, KY	Distribution*	138.00	34.50	14.00
22	Locust	Distribution*	69.00	12.47	
23	Lyndon, KY	Distribution*	69.00	12.47	
24	Lyndon South	Distribution*	69.00	12.47	
25	Lynn	Distribution*	13.80	4.16	
26	Madison	Distribution*	69.00	13.80	
27	Magazine	Distribution*	13.80	4.16	
28	Magazine	Distribution*	69.00	13.80	
29	Manslick	Distribution*	138.00	12.47	
30	Mill Creek	Distribution*	138.00	12.47	
31	Mud Lane	Distribution*	138.00	12.47	
32	Nachand	Distribution*	69.00	12.47	
33	Okolona	Distribution*	138.00	12.47	
34	Old Henry	Distribution*	138.00	12.47	
35	Oxmoor	Distribution*	69.00	12.47	
36	Paddy's Run	Distribution*	138.00	13.80	
37	Pirtle	Distribution*	13.80	4.16	
38	Plainview	Distribution*	138.00	12.47	
39	Pleasure Ridge Park	Distribution*	138.00	12.47	
40	Seminole	Distribution*	69.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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.
56	2		NONE			1
78	2		Ground Transformer	2	9	2
101	3		NONE			3
45	1		Ground Transformer	1	5	4
90	2		NONE			5
73	2		NONE			6
202	3		Ground Transformer	2	10	7
66	3		Ground Transformer	2	9	8
45	1		NONE			9
28	1		NONE			10
84	3		NONE			11
11	2		NONE			12
45	1		Ground Transformer	1	5	13
34	1		NONE			14
45	1		Ground Transformer	1	5	15
34	1		NONE			16
90	2		NONE			17
90	2		NONE			18
73	2		NONE			19
56	2		NONE			20
30	1		NONE			21
45	1		NONE			22
28	1		NONE			23
28	1		NONE			24
12	2		NONE			25
134	3		Ground Transformer	2	10	26
15	2		Ground Transformer	3	15	27
111	3		NONE			28
45	1		NONE			29
28	1		Ground Transformer	2	19	30
90	2		NONE			31
84	3		NONE			32
45	1		NONE			33
45	1		NONE			34
56	2		NONE			35
335	6		Ground Transformer	5	70	36
14	2		NONE			37
45	1		NONE			38
45	1		NONE			39
229	5		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/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	Seminole	Distribution*	69.00	12.47	
2	Seventh Street	Distribution*	13.80	4.16	
3	Shepherdsville, KY	Distribution*	69.00	12.47	
4	Shively	Distribution*	69.00	12.47	
5	Shively	Distribution*	69.00	13.80	
6	Skylight, KY	Distribution*	69.00	12.47	
7	Smyrna	Distribution*	69.00	12.47	
8	South Park	Distribution*	69.00	12.47	
9	South Park	Distribution*	69.00	34.50	14.00
10	Southern	Distribution*	13.80	4.16	
11	Stewart	Distribution*	69.00	12.47	
12	Taylor	Distribution*	69.00	12.47	
13	Terry	Distribution*	69.00	12.47	
14	Tip Top	Distribution*	138.00	34.50	28.00
15	Waterside West	DIstribution*	138.00	13.80	
16	Watterson	Distribution*	138.00	12.47	
17	West Point	Distribution*	34.50	12.47	
18	Western	Distribution*	13.80	4.16	
19	Worthington	Distribution*	69.00	12.47	
20	WHAS	Distribution*	69.00	12.47	
21	20 Stations Less Than 10 MVa				
22	Total Distribution		7182.90	1113.76	56.00
23					
24					
25					
26					
27					
28					
29	Summary				
30	Transmission 45				
31	Distribution 97				
32	Total 142				
33					
34	* Unattended				
35					
36					
37					
38					
39					
40					

Name of Respondent Louisville Gas and Electric Company	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	1		NONE			1
14	2		NONE			2
21	2		NONE			3
45	1		Ground Transformer	1	5	4
25	1		NONE			5
10	1		NONE			6
56	2		NONE			7
28	1		NONE			8
10	1		NONE			9
14	2		NONE			10
62	3		NONE			11
84	3		NONE			12
73	2		NONE			13
101	2		NONE			14
200	4		NONE			15
73	2		NONE			16
11	1		NONE			17
14	2		NONE			18
90	2		NONE			19
20	2		NONE			20
104	27		NONE			21
5409	188			48	290	22
						23
						24
						25
						26
						27
						28
						29
7213	39					30
5409	188			48	290	31
12622	227			48	290	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
Louisville Gas and Electric Company	(1) ☒ An Original (2) ☐ A Resubmission	/ /	End of 2013/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Capital Expenditures	Kentucky Utilities Company	see footnote	5,508,657
3	Direct-Indirect Labor	Kentucky Utilities Company	see footnote	1,139,227
4	Equipment and Facilities	Kentucky Utilities Company	see footnote	296,311
5	Office and Administrative Services	Kentucky Utilities Company	see footnote	83,705
6	Materials and Fuels	Kentucky Utilities Company	see footnote	30,728
7	Outside Services	Kentucky Utilities Company	see footnote	164,101
8				
9	Capital Expenditures	LG&E and KU Services Company	see footnote	29,417,382
10	Direct-Indirect Labor	LG&E and KU Services Company	see footnote	75,903,824
11	Equipment and Facilities	LG&E and KU Services Company	see footnote	10,376,640
12	Office and Administrative Services	LG&E and KU Services Company	see footnote	5,203,458
13	Materials and Fuels	LG&E and KU Services Company	see footnote	1,794,645
14	Outside Services	LG&E and KU Services Company	see footnote	13,330,198
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Capital Expenditures	Kentucky Utilities Company	see footnote	6,246,988
22	Direct-Indirect Labor	Kentucky Utilities Company	see footnote	8,432,774
23	Equipment and Facilities	Kentucky Utilities Company	see footnote	500,056
24	Office and Administrative Services	Kentucky Utilities Company	see footnote	14,508
25	Materials and Fuels	Kentucky Utilities Company	see footnote	235,049
26	Outside Services	Kentucky Utilities Company	see footnote	507,669
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40	See footnote for allocation process			
41				
42				

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2013/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: 183, 184, 232, 236, 408, 500, 506, 513, 546, 549, 551-554, 560, 561, 566, 570, 580, 581, 583, 592, 593, 598, 818, 880, 901, 903, 908, 920, 922, 925, 926 and 935

Schedule Page: 429 Line No.: 4 Column: c

Accounts charged include: 165, 184, 186, 426, 500-502, 506, 510, 513, 552, 560-563, 566, 570, 571, 573, 580-583, 586, 588, 592, 593, 598, 834, 856, 880, 887, 901, 903, 907, 908, 921, 925, 930 and 935

Schedule Page: 429 Line No.: 5 Column: c

Accounts charged include: 184, 426, 500, 501, 506, 549, 560, 566, 570, 580, 583, 588, 592-594, 598, 880, 887, 921, 930 and 935

Schedule Page: 429 Line No.: 6 Column: c

Accounts charged include: 163, 184, 506, 512, 513, 552, 560, 566, 570, 580, 586, 593, 598 and 921

Schedule Page: 429 Line No.: 7 Column: c

Accounts charged include: 163, 184, 500, 553, 560, 563, 566, 570, 571, 582, 586, 593, 902, 921 and 935

Schedule Page: 429 Line No.: 9 Column: c

Accounts charged include: 107 and 108

Schedule Page: 429 Line No.: 10 Column: c

Accounts charged include: 163, 183, 184, 186, 232, 236, 408, 426, 500-502, 505, 506, 510-514, 542, 548, 556, 560-563, 566, 570, 571, 573, 580-583, 586, 588, 590, 592, 593, 598, 834, 856, 880, 887, 901-903, 905, 907, 908, 920, 921, 925, 926, 930 and 935

Schedule Page: 429 Line No.: 11 Column: c

Accounts charged include: 163, 165, 183, 184, 186, 426, 500-502, 506, 510-514, 539, 542, 556, 560-563, 566, 570, 571, 573, 580-583, 586, 588, 593, 598, 818, 834, 856, 863, 878, 880, 887, 901-903, 905, 907, 908, 921, 923, 925, 930, 931 and 935

Schedule Page: 429 Line No.: 12 Column: c

Accounts charged include: 165, 184, 186, 426, 500-502, 506, 510-513, 539, 556, 560-563, 566, 570, 571, 573, 580-583, 586, 588, 590, 592, 593, 598, 807, 818, 821, 825, 856, 874, 877, 878, 880, 887, 892, 901-903, 905, 907-910, 920, 921, 923, 925, 930 and 935

Schedule Page: 429 Line No.: 13 Column: c

Accounts charged include: 163, 165, 184, 426, 500-502, 506, 510-514, 542, 560, 561, 566, 570, 573, 580, 583, 588, 593, 807, 816, 818, 877, 880, 901-903, 907-909, 921, 923 and 935

Schedule Page: 429 Line No.: 14 Column: c

Accounts charged include: 165, 184, 186, 426, 500-502, 506, 510-512, 514, 542, 553, 556, 560, 561, 566, 570, 580, 581, 583, 588, 592, 593, 598, 816, 818, 821, 863, 880, 887, 901-903, 905, 907-910, 921, 923, 930, 931 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: 163, 173, 183, 184, 232, 236, 408, 426, 500-502, 505, 506, 510-514, 535, 546, 548, 549, 552-554, 556, 560-562, 566, 570, 573, 580-583, 586, 588, 592-595, 598, 901-903, 905, 908, 920, 925, 926, 930 and 935

Schedule Page: 429 Line No.: 23 Column: c

Accounts charged include: 163, 165, 184, 186, 426, 454, 500, 501, 510-513, 550, 552-554, 556, 560-563, 566, 570, 571, 573, 580-583, 586, 588, 590, 592-595, 598, 901-903, 907, 925, 930, 931 and 935

Schedule Page: 429 Line No.: 24 Column: c

Accounts charged include: 158, 500, 506, 549, 553, 561, 566, 570, 580, 581, 583, 586, 588, 592, 594, 595, 598, 901, 903, 920, 921 and 935

Schedule Page: 429 Line No.: 25 Column: c

Accounts charged include: 158, 163, 184, 506, 511-514, 544, 550, 552-554, 562, 563, 566,

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

570, 573, 580, 583, 586, 588, 590, 592-594 and 923

Schedule Page: 429 Line No.: 26 Column: c

Accounts charged include: 184, 186, 500, 501, 550, 552-554, 562, 563, 566, 570, 573, 584, 588, 594, 595 and 923

Schedule Page: 429 Line No.: 40 Column: a

Costs between Louisville Gas and Electric Company and Kentucky Utilities Company are charged directly and are not allocated.

LG&E and KU Services Company (LKS) will allocate the costs of service among the affiliated companies using one of several methods that most accurately distributes the costs. The method of cost allocation varies based on the department rendering the service. Any of the methods may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes in the business, but are generally determined annually. The assignment methods currently used by LKS are as follows:

Contract Ratio – Based on the sum of the physical amount (i.e. tons of coal, cubic feet of natural gas) of the contract for both coal and natural gas for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Departmental Charge Ratio – A specific LKS department ratio based upon various factors. The departmental charge ratio typically applies to indirectly attributable costs such as departmental administrative, support, and/or material and supply costs that benefit more than one affiliate and that require allocation using general measures of cost causation. Methods for assignment are department-specific depending on the type of service being performed and are documented and monitored by the Budget Coordinators for each department. The numerator and denominator vary by department. The ratio is based upon various factors such as labor hours, labor dollars, departmental or entity headcount, capital expenditures, operations & maintenance costs, retail energy sales, charitable contributions, generating plant sites, average allocation of direct reports, net book value of utility plant, total line of business assets, electric capital expenditures, substation assets and transformer assets. These ratios are calculated on an annual basis. Any changes in these ratios will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in any of these ratios from that used in the prior year.

Electric Peak Load Ratio – Based on the sum of the monthly electric maximum system demands for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company and the denominator of which is for all operating companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Energy Marketing Ratio – Based on the absolute value of megawatt hours purchased and sold for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affiliate and the denominator of which is for all operating companies and affected affiliate companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Generation Ratio – Based on the annual forecast of megawatt hours, the numerator of which is for an operating company or an affiliate and the denominator of which is for all operating companies and affected affiliate companies. This ratio is calculated on an 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 dollars to total labor dollars. (LKC has no employees, but non-utility related labor is charged to it.) This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Number of Meters Ratio – Based on the number or types of meters being utilized by all levels of customer classes within the system for the immediately preceding twelve consecutive calendar months. The numerator is equal to the number of meters for each utility and the denominator is equal to the total meters for KU and LG&E. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Number of Transactions Ratio – Based on the sum of transactions occurring in the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. For example, services pertaining to Materials Logistics would define the transaction as the number of items ordered, picked and disbursed out of the warehouse. Services pertaining to Accounts Payable would define the transaction as the number of invoices processed. The Controller’s organization is responsible for maintaining and monitoring specific product/service methodology documentation for actual transactions related to 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.

Revenue Ratio – Based on the sum of the revenue for the immediately preceding twelve

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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2013/Q4

FOOTNOTE DATA

consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Revenue, Total Assets and Number of Employees Ratio – Based on an average of the revenue, total assets and number of employees ratios. This ratio is independently calculated for LG&E and KU. The numerator is the sum of Revenue Ratio, Total Assets Ratio and Number of Employees Ratio for the specific company. The denominator is three – the number of ratios being averaged. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Total Assets Ratio – Based on the total assets at year end for the preceding year. In the event of joint ownership of a specific asset, asset ownership percentages are utilized to assign costs. The numerator is the total assets for each specific company at the end of the preceding year. The denominator is the sum of total assets for each company in which an allocator is assigned (LG&E, KU and LKC). This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Total Utility Plant Assets Ratio – Based on the total utility plant assets at year end for the preceding year, the numerator of which is for an operating company or affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. In the event of joint ownership of a specific asset, ownership percentages are utilized to assign costs. This ratio is calculated on an annual basis. Any changes in the ratio will be determined no later than May 1st of the following calendar year, and charges to date will be reallocated for any significant changes in the ratio from that used in the prior year.

Transportation Resource Management System Chargeback Ratio – Based on the costs associated with providing and operating transportation fleet for all affiliated companies including developing fleet policy, administering regulatory compliance programs, managing repair and maintenance of vehicles and procuring vehicles. Such rates are applied based on the specific equipment employment and the measured usage of services by the various company entities. This ratio is calculated monthly based on the actual transportation charges from the previous month. The numerator is the department labor charged to a specific company. The denominator is the total labor costs for the specific department. The ratio is then multiplied by the total transportation costs to determine the amount charged to each company.

Ownership Percentages – Based on the contractual ownership percentages of jointly-owned generating units. This ratio is updated as a result of new jointly-owned generating units, and is based on the total forecasted energy needs. The numerator is the specific company’s forecasted incremental capacity and/or energy needs. The denominator is the total incremental capacity and/or energy needs of all companies.

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Schedule — Page No.

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INDEX (continued)

INDEX (continued)

INDEX (continued)

a PPL company

ANNUAL REPORT

Major Natural Gas Companies

Public Service Commission
of Kentucky

Exact Legal Name of Respondent (Company) Louisville Gas and Electric Company	**Year/Period of Report** End of 2013/Q4

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Principal Payment and Interest Information

	Amount	Yes/No
Amount of Principal Payment During Calendar Year	$0.00	
Is Principal Current?	Y	
Is Interest Current?	Y	

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Services Performed by Independent CPA

	Yes/No	A/C/R
Are your financial statements examined by a Certified Public Accountant?		
Enter Y for Yes or N for No	Y	
If yes, which service is performed?		
Enter an X on each appropriate line		
Audit		X
Compilation		
Review		
Please enclose a copy of the accountant’s report with annual report.		

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Purchases

	Seller	Acct	Gas Purc MCF	Cost of Gas
	Gas Purchases	803	36,892,187	$164,313,481.00
	Performance Based Ratemaking Incentive	803	0	$2,609,865.00
	Gas Supply Adjustments	803	0	($1,509,101.00)
	Wholesale Purchases	803	58,537	$224,400.00
Total			36,950,724	$165,638,645.00

Note:
See Notes 1 and 4 of Notes to Financial Statements for a full description of the Performance Based Ratemaking Incentive in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Additional Information - Counties

Barren, Bullitt, Green, Hardin, Hart, Henry, Jefferson, Larue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Spencer, Trimble, Washington

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Revenues, Customers and MCF Sales

	Revenues	MCFs Nat Gas Sold	Customers
Residential (480)	$208,708,911.00	21,101,535	292,810
Commercial and Industrial Sales (481)			
Small (or Commercial)	$75,448,710.00	9,202,365	24,724
Large (Or Industrial)	$11,841,637.00	1,680,362	317
Other Sales to Public Authorities (482)	$11,746,409.00	1,616,656	1,139
Interdepartmental Sales (484)	$7,065,104.00	601,132	2
Total Sales to Ultimate Customers	$314,810,771.00	34,202,050	318,992
Sales for Resale (483)	$256,500.00	58,537	1
Total Natural Gas Service	$315,067,271.00	34,260,587	318,993

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Identification (Ref Page: 1)

	Name	Address1	Address2	City	State	Zip	Phone
Exact Legal Name of Respondent							
	Louisville Gas and Electric Company						
Previous Name and Date of change (if name changed during the year)							
Name Address and Phone number of the contact person							
	T. Eric Raible	220 West Main Street	P.O. Box 32030	Louisville	KY	40202	5026273426
Note File: Attestation and signature via Electronic Filing							

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

General Information - (1) (Ref Page: 101)

	Name	Address	City	State	Zip
Provide name and title of the Officer having custody of the general corporate books of account	Kent W. Blake, Chief Financial Officer				
Provide Address of Office where the general Corporate books are kept		220 West Main Street	Louisville	KY	40202
Provide the Address of any other offices where other coprorate books are kept if different from where the general corporate books are kept					

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

General Information (2,3,4) (Ref Page: 101)

	Explain
Provide the name of the State under the laws which respondent is incorporated and date	
If incorporated under a special law give reference to such law	
If not incorporated state that fact and give the type of organization and the date organized	
	Kentucky July 2, 1913
If at any time during the year the property of respondent was held by a receiver or trustee	
give (a) the name of receiver or trustee	
(b) date such receiver or trustee took possession	
(c) the authority by which the receivership or trusteeship was created and	
(d) date when possession by receiver or trustee ceased.	
	Not Applicable
State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.	
	Respondent furnishes electric and natural gas services in the City of Louisville and adjacent territory in Kentucky.

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

General Information - (5) (Ref Page: 101)

	Yes/No	Date
Have you engaged as the principal acountant to audit your financial statements an accountant who is not the principal account for the previous years certified financial statements?	N	
Enter Y for Yes or N for No		
If yes, Enter the date when such independend accountant was initially engaged		

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Security Holders and Voting Powers - Part 1 (Ref Page: 107)

	Explain	Date	Total
1. Give date of the latest closing of the stock book prior to end of the year, and state the purpose of such closing:	Stock books not closed during the year.		
2. State the total number of votes cast at the latest general meeting prior to end of year for election of directors or the respondent and the number of such votes cast by proxy			
Total:			21,294,223
By Proxy:			21,294,223
3. Give the date and place of such a meeting	Louisville, KY	11/25/2013	
Voting Securities			
Number of votes as of Date:			21,294,223

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Security Holders and Voting Powers - Part 2 (Ref Page: 107)

	Name	Address	Total Votes	Common Stock	Preferred Stock	Other
4. Total votes of all voting securities			21,294,223	21,294,223	0	0
5. Total number of all security holders			1	1	0	0
6. Total Votes of Security Holders listed below						
	LG&E and KU Energy LLC	Louisville, KY	21,294,223	21,294,223	0	0

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Important Changes During the Year (Ref Page: 108)

	Explain
Give particulars concerning the matters indicated below.	
1. Changes in and important additions to franchise rights:	None.
2. Acquisition of ownership in other companies by reorganization, merger or consolidation with other companies:	None.
3. Purchase or sale of an operating unit or system:	None.
4. Important leaseholds (other than leaseholds for natural gas lands) thant have been accquired or given assigned or surrendered:	None of a material nature.
5. Important extension or reduction of transmission or distribution system:	None.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees.	LG&E issued long-term first mortgage bonds totaling $250 million on November 14, 2013. The bonds mature in November 2043 and have an interest rate of 4.65%. This transaction was approved by the KPSC on August 3, 2012, in Case No. 2012-00233. LG&E received FERC authorization in FERC Docket No. ES13-54-000 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, 2015. LG&E's money pool balance was zero at December 31, 2013, and December 31, 2012, respectively. LG&E established a commercial paper program in February 2012, allowing issuance of up to $250 million. The program was increased to $350 million effective April 1, 2013. As of December 31, 2013, and December 31, 2012, the outstanding commercial paper balance is $20 million and $55 million, respectively.
7. Changes in articles of incoporation or amendments to charter: Explain the nature and purpose of such changes or amendments.	None.
8. State the estimated annual effect and nature of any important wage scale changes during the year.	During the first quarter of 2013, exempt and non-exempt employees received routine wage increases in accordance with annual salary reviews. As outlined in the IBEW Local 2100 contract, union employees received a negotiated wage increase of 2.5% effective November 11, 2013.
9. State briefly the status of any materially important legal proceedings pending at the end of the year and the results.	See Notes 4 and 10 of Notes to Financial Statements on page 123.
10. Describe briefly any materially important transactions not disclosed elsewhere in this report in which an officer, director, or associated company was a party or had a material interest.	None.
11. Estimated increase or decrease in annual revenues caused by important rate changes.	Not applicable.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
1. UTILITY PLANT		
2. Utility Plant (101-106,114)	$4,881,636,687.00	$5,067,913,274.00
3, Construction Work in Progress (107)	$258,364,758.00	$651,432,116.00
4. TOTAL UTILITY PLANT	$5,140,001,445.00	$5,719,345,390.00
5. (Less) Accum. Prov. for Depr. Amort. Depl. (108,111,115)	$2,201,756,057.00	$2,304,132,232.00
6. Net Utility Plant (Line 4 less Line 5)	$2,938,245,388.00	$3,415,213,158.00
7. Nuclear Fuel (120.1-120.4,120.6)	$0.00	$0.00
8. (Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)	$0.00	$0.00
9. Nuclear Fuel (Line 7 less Line 8)	$0.00	$0.00
10. Net Utility Plant (Enter Total of Line 6 and Line 9)	$2,938,245,388.00	$3,415,213,158.00
11. Utility Plant Adjustments (116)	$0.00	$0.00
12. Gas Stored-Base Gas (117.1)	$2,139,990.00	$2,139,990.00
13. System Balancing Gas (117.2)	$0.00	$0.00
14. Gas Stored Underground - Non Current (117.3)	$0.00	$0.00
15. Gas Owned to System Gas (117.4)	$0.00	$0.00
16. OTHER PROPERTY AND INVESTMENTS		
17. Nonutility Property (121)	$592,759.00	$552,781.00
18. (Less) Accum. Prov. for Depr and Amort. (122)	$65,709.00	$63,360.00
19. Investment in Associated Companies (123)	$0.00	$0.00
20. Investments in Subsidiary Companies (123.1)	$594,286.00	$594,286.00
21.		
22. Noncurrent Portion of Allowances	$0.00	$0.00
23. Other Investments (124)	$0.00	$0.00
24. Special Funds (125-128)	$31,747,624.00	$22,225,512.00
25. TOTAL Other Property and Investments	$32,868,960.00	$23,309,219.00
26. CURRENT AND ACCRUED ASSETS		
27. Cash (131)	$7,372,093.00	$3,467,771.00
28. Special Deposits (132-134)	$0.00	$0.00
29. Working Fund (135)	$20,090.00	$20,090.00
30. Temporary Cash Investments (136)	$14,316,601.00	$4,534,363.00
31. Notes Receivable (141)	$0.00	$0.00
32. Customer Accounts Receivable (142)	$60,348,949.00	$102,699,981.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
33. Other Accounts Receivable (143)	$16,119,508.00	$9,932,099.00
34. (Less) Accum. Prov. for Uncollectible Acct. Credit (144)	$1,218,026.00	$1,828,849.00
35. Notes Receivable from Associated Companies (145)	$0.00	$0.00
6. Accounts Receivable from Assoc. Companies (146)	$13,662,418.00	$108,735.00
37. Fuel Stock (151)	$61,099,619.00	$64,191,758.00
38. Fuel Stock Expenses Undistributed (152)	$0.00	$0.00
39. Residuals (Elec) and Extracted Products (153)	$0.00	$0.00
40. Plant Materials and Operating Supplies (154)	$32,727,610.00	$35,816,745.00
41. Merchandise (155)	$0.00	$0.00
42. Other Materials and Supplies (156)	$0.00	$0.00
43. Nuclear Materials Held for Sale (157)	$0.00	$0.00
44. Allowances (158.1 and 158.2)	$1,771.00	$41,739.00
45. (Less) Noncurrent Portion of Allowances	$0.00	$0.00
46. Stores Expense Undistributed (163)	$5,860,024.00	$6,186,832.00
47. Gas Stored Underground - Current (164.1)	$42,010,154.00	$47,546,888.00
48. Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	$0.00	$0.00
49. Prepayments (165)	$6,976,761.00	$5,125,670.00
50. Advances for Gas (166-167)	$0.00	$0.00
51. Interest and Dividends Receivable (171)	$28,358.00	$25,490.00
52. Rents Receivable (172)	$332,546.00	$536,817.00
53. Accrued Utility Revenues (173)	$72,143,278.00	$85,152,363.00
54. Miscellaneous Current and Accrued Assets (174)	$0.00	$0.00
54.a Derivative Instrument Assets (175)	$7,142,276.00	$0.00
54.b Derivative Instrument Assets - Hedges (176)	$0.00	$0.00
55. TOTAL Current and Accrued Assets (Lines 27 - 54.b)	$338,944,030.00	$363,558,492.00
56. DEFERRED DEBITS		
57. Unamortized Debt Expenses (181)	$9,831,700.00	$10,857,401.00
58. Extraordinary Property Losses (181.1)	$0.00	$0.00
59. Unrecovered Plant and Regulatory Study Costs (182.2)	$0.00	$0.00
60. Other Regulatory Assets (182.3)	$413,428,343.00	$316,510,769.00
61. Prelim. Survey and Investigation Charges (Electric) (183)	$1,567,192.00	$561,651.00

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
62. Prelim. Sur. and Invest. Charges (Gas) (183.1,183.2)	$0.00	$0.00
63. Clearing Accounts (184)	$0.00	$0.00
64. Temporary Facilities (185)	$0.00	$0.00
65. Miscellaneous Deferred Debits (186)	$527,590,338.00	$503,728,950.00
66. Def. Losses from Disposition of Utility Plt. (187)	$0.00	$0.00
67. Research, Devel. and Demonstration Expend. (188)	$0.00	$0.00
68. Unamortized Loss on Reacquired Debt (189)	$19,968,045.00	$18,442,649.00
69. Accumulated Deferred Income Taxes (190)	$163,506,960.00	$174,804,497.00
70. Unrecovered Purchased Gas Costs (191)	$0.00	$0.00
71. TOTAL Deferred Debits (Lines 57-70)	$1,135,892,578.00	$1,024,905,917.00
72. Total Assets and other Debits (Total Lines 10-15,22,55,71)	$4,448,090,946.00	$4,829,126,776.00

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Balance Sheet - Liabilities and Other Credits (Ref Page: 112)

	Balance Beginning of Year	Balance End of Year
1. PROPRIETARY CAPITAL		
2. Common Stock Issued (201)	$425,170,424.00	$425,170,424.00
3. Preferred Stock Issued (204)	$0.00	$0.00
4. Capital Stock Subscribed (202,205)	$0.00	$0.00
5. Stock Liability for Conversion (203,206)	$0.00	$0.00
6. Premium on Capital Stock (207)	$0.00	$0.00
7. Other Paid-in Capital Stock (208-211)	$1,277,667,368.00	$1,363,667,368.00
8. Installments Received on Capital stock (212)	$0.00	$0.00
9. (Less) Discount on Capital Stock (213)	$0.00	$0.00
10. (Less) Capital Stock Expense (214)	$835,889.00	$835,889.00
11. Retained Earnings (215,215.1,216)	$108,052,874.00	$172,457,991.00
12. Unappropriated Undistributed Subsidaiary Earnings (216.1)	$0.00	$0.00
13. (Less) Reacquired Capital Stock (217)	$0.00	$0.00
14. Accumulated Other Comprehensive Income (219)	$0.00	$0.00
15. TOTAL Proprietary Capital	$1,810,054,777.00	$1,960,459,894.00
16. LONG TERM DEBT		
17. Bonds (221)	$1,109,304,000.00	$1,359,304,000.00
18. (Less) Reacquired Bonds (222)	$0.00	$0.00
19. Advances from Associated Companies (223)	$0.00	$0.00
20. Other Long-Term Debt (224)	$5,926,259.00	($1,773,437.00)
21. Unamortized Premium on Long-Term Debt (225)	$0.00	$0.00
22. (Less) Unamortized Discount on LongTerm Debt (226)	$3,388,598.00	$4,901,231.00
23. (Less) Current Portion of Long Term Debt	$0.00	$0.00
24. TOTAL Long Term Debt	$1,111,841,661.00	$1,352,629,332.00
25. OTHER NONCURRENT LIABILITIES		
26. Obligations Under Capital Leases-NonCurrent (227)	$0.00	$0.00
27. Accumulated Provision for Property Insurance (228.1)	$0.00	$0.00
28. Accumulated Provision for Injuries and Damages (228.2)	$5,122,022.00	$4,329,048.00
29. Accumulated Provision for Pensions and Benefits (228.3)	$186,312,334.00	$95,101,935.00
30. Accumulated Miscellaneous Operating Provisions (228.4)	$0.00	$0.00
31. Accumulated Provision for Rate Refunds (229)	$0.00	$0.00
32. Asset Retirement Obligations (230)	$64,684,737.00	$82,196,215.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Balance Sheet - Liabilities and Other Credits (Ref Page: 112)

	Balance Beginning of Year	Balance End of Year
33. TOTAL OTHER Noncurrent Liabilities	$256,119,093.00	$181,627,198.00
34. CURRENT AND ACCRUED LIABILITIES		
35. Current Portion of Long-Term Debt	$0.00	$0.00
36. Notes Payable (231)	$54,992,670.00	$19,996,778.00
37. Accounts Payable (232)	$121,578,266.00	$170,850,243.00
38. Notes Payable to Associated Companies (233)	$0.00	$0.00
39. Account Payable to Associated Companies (234)	$22,801,659.00	$24,294,741.00
40. Customer Deposits (235)	$23,464,189.00	$24,075,549.00
41. Taxes Accrued (236)	$1,735,495.00	$11,474,666.00
42. Interest Accrued (237)	$5,118,488.00	$5,580,258.00
43. Dividends Declared (238)	$0.00	$0.00
44. Matured Long-Term Debt (239)	$0.00	$0.00
45. Matured Interests (240)	$0.00	$0.00
46. Tax Collections Payable (241)	$1,309,572.00	$1,419,912.00
47. Miscellaneous current and Accrued Liabilities (242)	$19,168,503.00	$18,912,401.00
48. Obligatons Under Capital Leases - Current (243)	$0.00	$0.00
49. Derivative Instrument Liabilities (244)	$30,990,202.00	$35,912,921.00
50. Derivative Instrument Liabilties - Hedges (245)	$27,615,282.00	$0.00
51. TOTAL Current and Accrued Liabilities	$308,774,326.00	$312,517,469.00
52. DEFERRED CREDITS		
53. Customer Advances for Construction (252)	$6,709,975.00	$6,748,025.00
54. Accumulated Deferred Investment Tax Credits (255)	$39,871,227.00	$37,770,885.00
55. Deferred Gains from Disposition of Utility Plant (256)	$0.00	$0.00
56. Other Deferred Credits (253)	$9,080,813.00	$17,863,555.00
57. Other Regulatory Liabilities (254)	$194,283,183.00	$206,203,422.00
58. Unamortized gain on Reacquired Debt (257)	$0.00	$0.00
59. Accumulated Deferred Income Taxes (281-283)	$711,355,891.00	$753,306,996.00
60. TOTAL Deferred Credits	$961,301,089.00	$1,021,892,883.00
61. TOTAL Liabilities and Other Credits (Total Lines 15,24,33,51 and 60)	$4,448,090,946.00	$4,829,126,776.00

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Balance Sheet - Liabilities and Other Credits (Ref Page: 112) - NOTES

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Statement of Income for the Year (Ref Page: 114)

	Total (c)	Total - Prev Yr (d)	Electric (e)	Gas (g)	Other (i)
1..UTILITY OPERATING INCOME					
2. Gas Operating Revenues (400)	$1,420,817,715.00	$1,323,624,802.00	$1,096,596,441.00	$324,221,274.00	$0.00
3. Operating Expenses					
4. Operation Expenses (401)	$831,716,786.00	$784,377,726.00	$625,928,383.00	$205,788,403.00	$0.00
5. Maintenance Expenses (402)	$113,413,021.00	$118,770,589.00	$95,645,484.00	$17,767,537.00	$0.00
6. Depreciation Expense (403)	$139,714,329.00	$143,303,463.00	$115,965,636.00	$23,748,693.00	$0.00
7. Depreciation Expense for Asset Retirement Costs (403.1)	$0.00	$2,987,801.00	$0.00	$0.00	$0.00
8. Amort and Depl of Utility Plant (404-405)	$7,948,703.00	$8,836,853.00	$5,643,550.00	$2,305,153.00	$0.00
9. Amort of Utility Plant Acq. Adj (406)	$0.00	$0.00	$0.00	$0.00	$0.00
10. Amort of Property Losses, Unrecovered Plant and Regulatory Study Costs (407.1)	$0.00	$0.00	$0.00	$0.00	$0.00
11. Amort. of Conversion Expenses (407.2)	$0.00	$0.00	$0.00	$0.00	$0.00
12. Regulatory Debits (407.3)	$0.00	$0.00	$0.00	$0.00	$0.00
13. (Less) Regulatory Credits (407.4)	$0.00	$5,915,937.00	$0.00	$0.00	$0.00
14. Taxes Other than Income Taxes (408.1)	$32,517,048.00	$31,025,991.00	$25,031,903.00	$7,485,145.00	$0.00
15. Income Taxes - Federal (409.1)	$53,107,974.00	($596,880.00)	$41,181,745.00	$11,926,229.00	$0.00
16. Income Taxes - Other (409.1)	$16,078,249.00	$2,588,533.00	$13,122,319.00	$2,955,930.00	$0.00
17. Provision for Deferred Income Taxes (410.1)	$211,251,945.00	$179,830,059.00	$167,982,718.00	$43,269,227.00	$0.00
18. (Less) Provision for Deferred Income Taxes (411.1)	$183,189,299.00	$108,743,665.00	$148,438,529.00	$34,750,770.00	$0.00
19. Investment Tax Credit Adj. - Net (411.4)	($2,100,342.00)	($2,847,617.00)	($1,987,122.00)	($113,220.00)	$0.00
20. (Less) Gains from Disp. of Utility Plant (411.6)	$0.00	$0.00	$0.00	$0.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Statement of Income for the Year (Ref Page: 114)

	Total (c)	Total - Prev Yr (d)	Electric (e)	Gas (g)	Other (i)
21. Losses from Disp. of Utility Plant (411.7)	$0.00	$0.00	$0.00	$0.00	$0.00
22. (Less) Gains from Disposition of Allowances (411.8)	$282.00	$694.00	$282.00	$0.00	$0.00
23. Losses from Disposition of Allowances (411.9)	$0.00	$0.00	$0.00	$0.00	$0.00
24. Accretion Expense (411.10)	$0.00	$2,928,136.00	$0.00	$0.00	$0.00
25. Total Utility Operating Expenses (Enter Total of Lines 4 - 22)	$1,220,458,132.00	$1,156,544,358.00	$940,075,805.00	$280,382,327.00	$0.00
26. Net Utility Operating Income (Line 2 less line 23 - Carry forward to pg 117 line 25)	$200,359,583.00	$167,080,444.00	$156,520,636.00	$43,838,947.00	$0.00

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Statement of Income (continued) (Ref Page: 116)

	Current Year	Previous Year
27. Net Utility Operating Income (Carried from pg 114)	$200,359,583.00	$167,080,444.00
28. Other Income and Deductions		
29. Other Income		
30. Nonutility Operating Income		
31. Revenues From Merchandising, Jobbing and Contract Work (415)	$45,217.00	$13,925.00
32. (Less) Costs and Exp. of Merchandising,Job. and Contract Work (416)	$36,633.00	$25,335.00
33. Revenues From Nonutility Operations (417)	$1,265,429.00	$1,267,144.00
34. (Less) Expenses of Nonutility Operations (417.1)	$0.00	$0.00
35. Nonoperating Rental Income (418)	$0.00	$0.00
36. Equity in Earnings of Subsidiary Companies (418.1)	$0.00	$0.00
37. Interest and Dividend Income (419)	$117,128.00	$186,894.00
38. Allowance for Other Funds Used During Construction (419.1)	$0.00	$0.00
39. Miscellaneous Nonoperating Income (421)	$234.00	$8,526.00
40. Gain on Disposition of Property (421.1)	$16,540.00	$122,175.00
41. TOTAL Other Income	$1,407,915.00	$1,573,329.00
42. Other Income Deductions		
43. Loss on Disposition of Property (421.2)	$12,001.00	$0.00
44. Miscellaneous Amortization (425)	$0.00	$0.00
45. Miscellaneous Income Deductions (426.1 - 426.5)	$5,308,049.00	$4,411,032.00
46.TOTAL Other Income Deductions	$5,320,050.00	$4,411,032.00
47. Taxes Applic. to Other Income and Deductions		
48. Taxes Other Than Income Taxes (408.2)	$5,960.00	$3,564.00
49. Income Taxes - Federal (409.2)	($1,255,593.00)	($977,712.00)
50. Income Taxes - Other (409.2)	($192,086.00)	$406,552.00
51. Provision for Deferred Inc. Taxes (410.2)	$205,595.00	$740.00
52. (Less) Provision for Deferred Income Taxes CR (411.2)	$19,165.00	$219,065.00
53. Investment Tax Credit Adj. Net (411.5)	$0.00	$0.00
54. (Less) Investment Tax Credits (420)	$0.00	$0.00
55. TOTAL Taxes on Other Income and Deduct.	($1,255,289.00)	($785,921.00)
56. Net Other Income and Deductions (Lines 39,44,53)	($2,656,846.00)	($2,051,782.00)

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Statement of Income (continued) (Ref Page: 116)

	Current Year	Previous Year
57. Interest Charges		
58. Interest on Long Term Debt (427)	$28,812,421.00	$36,698,051.00
59. Amort of Debt Disc. and Expense (428)	$2,906,102.00	$2,072,123.00
60. Amortization of Loss on Reacquired Debt (428.1)	$1,048,550.00	$1,230,292.00
61. (Less) Amort. of Premium on Debt - CR (429)	$0.00	$0.00
62. (Less) Amortization of Gain on Reacquired Debt - CR (429.1)	$0.00	$0.00
63. Interest on Debt to Assoc. Companies (430)	$10,061.00	$3,429.00
64. Other Interest Expense (431)	$1,520,486.00	$1,918,559.00
65. (Less) Allowance for Borrowed Funds Used During Construction CR (432)	$0.00	$0.00
66. Net Interest Charges	$34,297,620.00	$41,922,454.00
67. Income Before Extraordinay Items (Lines 25,54 and 64)	$163,405,117.00	$123,106,208.00
68. Extraordinary Items		
69. Extraordinary Income (434)	$0.00	$0.00
70. (Less) Extraordinary Deductions (435)	$0.00	$0.00
71. Net Extraordinary Items (Lines 67 less 68)	$0.00	$0.00
72. Income Taxes - Federal and Other (409.3)	$0.00	$0.00
73. Extraordinary Items After Taxes (Lines 69 less 70)	$0.00	$0.00
74. Net Income (Lines 67 and 73)	$163,405,117.00	$123,106,208.00

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Statement of Retained Earnings for the Year (Ref Page: 118)

Item (a)	Acct (b)	Amount (c)
UNAPPROPRIATED RETAINED EARNINGS (216)		
State balance and purpose of each appropriated retained earnings amount at end of year and		
1. Balance - Beginning of the Year		$108,052,874.00
Changes (Identify by prescribed retained earnings accounts)		
give accounting entries for any applications of appropriated retained earnings during the year.		
Adjustments to Retained Earnings (439)		
Credit:		
4. TOTAL Credits to Retained Earnings (439)		
Debit:		
5. TOTAL Debits to Retained Earnings (439)		
6. Balance Transferred from Income (433 less 418.1)	0	$163,405,117.00
Appropriations of Retained Earnings (436)		
8. TOTAL appropriations of Retained Earnings (436)		
Dividends Declared - Preferred stock (437)		
10. TOTAL Dividends Declared - Preferred Stock (437)		
Dividends Declared - Common Stock (438)		
	0 Without Par Value	($99,000,000.00)
12. TOTAL Dividends Declared - Common Stock (438)		($99,000,000.00)
13. Transfers from Acct 216.1, Unappropriated Undistributed Subsidary Earnings		
14. Balance End of Year (Total Lines 1,4,5,6,8,10,12,13)		$172,457,991.00
APPROPRIATED RETAINED EARNINGS (215)		
(215)		
16. TOTAL Appropriated Retained Earnings (215)		

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Statement of Retained Earnings for the Year (Ref Page: 118)

Item (a)	Acct (b)	Amount (c)
APPROPRIATED RETAINED EARNINGS - AMORTIZATION RESERVE, FEDERAL		
17.TOTAL Appropriated Retained Earnings - Amortization Reserve, Federal (215.1)		
18. TOTAL Appropriated Retained Earnings (total lines 16 and 17) (214,215.1)		
19. TOTAL Retained Earnings (Lines 14 and 18) (215, 215.1, 216)		$172,457,991.00
UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (216.1)		
20. Balance - Beginning of Year (Debit or Credit)		
21. Equity in Earnings for Year (Credit) (418.1)		
22. (Less) Dividends Received (Debit)		
23. Other Charges (explain)		
24. Balance - End of Year		

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Statement of Cash Flows (Ref Page: 120)

	Description	Amounts
1. Net Cash Flow From Operating Activities:		
2. Net Income (Line 72 c on page 117)		$163,405,117.00
3. Noncash Charges (Credits) to Income:		
4. Depreciation and Depletion		$139,714,329.00
Amortization of (Specifiy)		
5.	Plant	$7,948,703.00
6. Deferred Income Taxes (Net)		$27,658,386.00
7. Investment Tax Credit Adjustment (Net)		($2,100,342.00)
8. Net (Increase) Decrease in Receivables		($32,386,979.00)
9. Net (Increase) Decrease in Inventory		($12,325,357.00)
10. Net (Increase) Decrease in Allowances Inventory		($39,968.00)
11. Net Increase (Decrease) in Payables and Acccrued Expenses		($31,719,957.00)
12. Net (Increase) Decrease in Other Regulatory Assets		$46,439,594.00
13. Net Increase (Decrease) in Other Regulatory Liabilities		$85,664,526.00
14. (Less) Allowance for Other Funds Used During Construction		
15. (Less) Undistributed Earnings from Subsidiary Companies		
Other:		
16.	Other	($46,549,895.00)
16.	Change in Other Deferred Debits	$348,774.00
16.	Change in Other Deferred Credits	$9,819,725.00
16.	0	$0.00
16.	0	$0.00
16.	0	$0.00
16.	0	$0.00
17. Net Cash Provided by (Used in) Operating Activities (Total lines 2 thru 16)		$355,876,656.00
Cash Flows from Investment Activities:		
21. Construction and Acquisition of Plant (Including Land):		
22. Gross Additions to Utility Plant (Less nuclear fuel)		($539,449,786.00)
23. Gross Additions to Nuclear Fuel		$0.00
24. Gross Additions to Common Utility Plant		($23,308,315.00)

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Statement of Cash Flows (Ref Page: 120)

	Description	Amounts
25. Gross Additons to Nonutility Plant		
26. (Less) Allowance for Other Funds Used During Construction		
Other		
27.	Other	($13,869,115.00)
Cash Outflows for Plant (Total lines 22-27)		($576,627,216.00)
30. Acquisition of Other Noncurrent Assets (d)		
31. Proceeds from Disposal of Noncurrent Assets (d)		$32,680.00
32. Retirements of Property,Plant and Equipment		
33. Investments in and Advances to Assoc. and Subsidary Companies		
34. Contributions and Advances from Assoc. and Subsidiary Companies		
35. Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
37. Purchase of Investment Securities (a)		
38. Proceeds from Sales of Investment Securities (a)		
40. Loans Made or Purchased		
41. Collections on Loans		
43. Net (Increase) Decrease in Receivables		
44. Net (Increase) Decrease in Inventory		
45. Net (Increase) Decrease in Allowances Held for Speculation		
46. Net Increase (Decrease) in Payables and Accrued Expenses		
Other:		
47.	Change in Restricted Cash	$9,522,111.00
48. Net Cash Provided by (used in) investing Activities (Lines 28-47)		($567,072,425.00)
Cash Flows from Financing Activities:		
52. Proceeds from Issuance of:		
53. Long - Term Debt (b)		$245,509,209.00
54. Preferred Stock		
55. Common Stock		
Other		
56		

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Statement of Cash Flows (Ref Page: 120)

Description		Amounts
57. Net Increase in Short-Term Debt (c)		($35,000,000.00)
Other		
58.		
59. Cash Provided by Outside Sources (Total lines 53-58)		$210,509,209.00
61. Payments for Retirement of		
62. Long-Term Debt (b)		
63. Preferred Stock		
64. Common Stock		
Other		
65.	Other	$86,000,000.00
66. Net Decrease in Short-Term Debt (c)		
68. Dividends on Preferred Stock		
69. Dividends on Common Stock		($99,000,000.00)
70. Net Cash Provided by (used in) Financing Activities (Lines 59-69)		$197,509,209.00
Net Increase (Decrease) in Cash and Cash Equivalents (Total Lines 18,49,71)		($13,686,560.00)
Cash and Cash Equivalents at Beginning of Year		$21,688,694.00
Cash and Cash Equivalents at End of Year		$8,002,134.00

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Summary of Utility Plant and Accumulated Provisions for Depreciation Amortization and Depletion (Ref Page: 200)

	Total (b)	Electric (c)	Gas (d)	Other (Total)	Common (h)
Utility Plant					
In Service					
3. Plant in Service (Classified)	$4,922,870,818.00	$3,895,298,143.00	$798,538,429.00	$0.00	$229,034,246.00
4. Property under Capital Leases					
5. Plant Purchased or Sold					
6. Completed Construction not Classified	$139,519,260.00	$87,809,623.00	$44,112,888.00	$0.00	$7,596,749.00
7. Experimental Plant Unclassifed					
8. Total - Utility Plant (Lines 3-7)	$5,062,390,078.00	$3,983,107,766.00	$842,651,317.00	$0.00	$236,630,995.00
9. Leased to Others					
10. Held for Future Use	$5,523,196.00	$5,523,196.00	$0.00	$0.00	$0.00
11. Construction Work in Progress	$651,432,116.00	$575,597,121.00	$55,354,723.00	$0.00	$20,480,272.00
12. Acquisition Adjustments					
13. Total Utility Plant (Lines 8 - 12)	$5,719,345,390.00	$4,564,228,083.00	$898,006,040.00	$0.00	$257,111,267.00
14. Accum. Prov. for Depr, Amort, And Depl.	$2,304,132,232.00	$1,925,796,828.00	$261,129,738.00	$0.00	$117,205,666.00
15. Net Utility Plant (Line 13 less 14)	$3,415,213,158.00	$2,638,431,255.00	$636,876,302.00	$0.00	$139,905,601.00
16. Detail of Accumulated Provisions for Depreciation Amortization and Depletion					
17. In Service					
18. Depreciation	$2,273,475,442.00	$1,925,766,839.00	$261,129,697.00	$0.00	$86,578,906.00
19. Amort. and Depl. of Production Natural Gas Land and Land Rights					
20. Amort of Underground Storage Land and Land Rights	$41.00	$0.00	$41.00	$0.00	$0.00
21. Amort of Other Utility Plant	$30,626,760.00	$0.00	$0.00	$0.00	$30,626,760.00
22. Total In Service (Lines 18-21)	$2,304,102,243.00	$1,925,766,839.00	$261,129,738.00	$0.00	$117,205,666.00
23. Leased to Others					

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Summary of Utility Plant and Accumulated Provisions for Depreciation Amortization and Depletion (Ref Page: 200)

	Total (b)	Electric (c)	Gas (d)	Other (Total)	Common (h)
24. Depreciation					
25. Amortization and Depletion					
26. Total Leased to Others (Lines 24 and 25)					
27. Held for Future Use					
28. Depreciation	$29,989.00	$29,989.00	$0.00	$0.00	$0.00
29. Amortization					
30. Total Held for Future Use (Lines 28 and 29)	$29,989.00	$29,989.00	$0.00	$0.00	$0.00
31. Abandonment of Leases (Naturual Gas)					
32. Amort. Of Plant Aquision Adj.					
33. Total Accumulated Provisions (Should agree with Line 14, Total 22,26,30,31 and 32)	$2,304,132,232.00	$1,925,796,828.00	$261,129,738.00	$0.00	$117,205,666.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Plant in Service - Intangible and Production Plant (Ref Page: 204)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
INTANGIBLE PLANT						
2. Organization (301)						
3. Franchises and Consents (302)	$387.00	$0.00	$0.00	$0.00	$0.00	$387.00
4. Miscellaneous Intangible Plant (303)						
5. Total Intangible Plant	$387.00	$0.00	$0.00	$0.00	$0.00	$387.00
PRODUCTION PLANT						
7. Natural Gas Production and Gathering Plant						
8. Producing Lands (325.1)						
9. Producing Leaseholds (325.2)						
10. Gas Rights (325.3)						
11. Rights of Way (325.4)						
12. Other Land and Land Rights (325.5)						
13. Gas Well Structures (326)						
14. Field Compressor Station Structures (327)						
15. Field Measuring and Regulating Station Equipment (328)						
16. Other Structures (329)						
17. Producing Gas Wells - Well Construction (330)						
18. Producing Gas Wells - Well Equipment (331)						
19. Field Lines (332)						
20. Field Compressor Station Equipment (333)						
21. Field Measuring and Regulating Station Equipment (334)						
22. Drillnig and Cleaning Equipment (335)						

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Gas Plant in Service - Intangible and Production Plant (Ref Page: 204)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
23. Purification Equipment (336)						
24. Other Equipment (337)						
25. Unsuccessful Exploration and Development Costs (338)						
26. Asset Retirement Costs for Natural Gas Production and Gathering Plant (339)						
27. Total Production and Gathering Plant						
28. PRODUCTS EXTRACTION PLANT						
29. Land and Land Rights (340)						
30. Structures and Improvements (341)						
31. Extraction and Refining Equipment (342)						
32. Pipe Lines (343)						
33. Extracted Products Storage Equipment (344)						
34. Compressor Equipment (345)						
35. Gas Measuring and Regulating Equipment (346)						
36. Other Equipment (347)						
37. Asset Retirement Costs for Products Extraction Plant (348)						
38. Total Products Extraction Plant						
39. Total Natural Gas Production Plant (Lines 27 and 38)						
40. Manufactured Gas Production Plant						

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Gas Plant in Service - Intangible and Production Plant (Ref Page: 204)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
41. Total Production Plant (Lines 39 and 40)						

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Gas Plant in Service - Storage and Processing (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
NATURAL GAS STORAGE AND PROCESSING PLANT						
Underground Storage Plant						
44. Land (350.1)	$32,865.00	$0.00	$0.00	$0.00	$0.00	$32,865.00
45. Rights-of-Way (350.2)	$95,613.00	$7,093.00	$0.00	$0.00	$0.00	$102,706.00
46. Structures and Improvements (351)	$8,453,877.00	$540,742.00	($136,359.00)	$0.00	$0.00	$8,858,260.00
47. Wells (352)	$20,363,502.00	($278,959.00)	($156,056.00)	$0.00	$0.00	$19,928,487.00
48. Storage Leaseholds and Rights (352.1)	$548,241.00	$0.00	$0.00	$0.00	$0.00	$548,241.00
49. Reservoirs (352.2)	$400,511.00	$0.00	$0.00	$0.00	$0.00	$400,511.00
50. Non-recoverable Natural Gas (352.3)	$9,648,855.00	$0.00	$0.00	$0.00	$0.00	$9,648,855.00
51. Lines (353)	$17,750,626.00	$820,104.00	($88,601.00)	$0.00	$0.00	$18,482,129.00
52. Compressor Station Equipment (354)	$16,938,788.00	$939,689.00	($103,148.00)	$0.00	$0.00	$17,775,329.00
53. Measuring and Regulating Equipment (355)	$580,756.00	$46,440.00	$0.00	$0.00	$0.00	$627,196.00
54. Purification Equipment (356)	$13,763,506.00	$643,333.00	($414,543.00)	$0.00	$0.00	$13,992,296.00
55. Other Equipment (357)	$1,759,976.00	($15,184.00)	($24,779.00)	$0.00	$0.00	$1,720,013.00
56. Asset Retirement Costs for Underground Storage Plant (358)	$4,198,268.00	$316,025.00	($47,890.00)	$0.00	$0.00	$4,466,403.00
57. Total Underground Storage Plant	$94,535,384.00	$3,019,283.00	($971,376.00)	$0.00	$0.00	$96,583,291.00
Other Storage Plant						
59. Land and Land Rights (360)						
60. Structures and Imporvements (361)						
61. Gas Holders (362)						
62. Purification Equipment (363)						

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Gas Plant in Service - Storage and Processing (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
63. Liquefaction Equipment (363.1)						
64. Vaporaizing Equipment (363.2)						
65. Compressor Equipment (363.3)						
66. Measuring and Regulating equipment (363.4)						
67. Other Equipment (363.5)						
68. Asset Retirement Costs for Other Storage Plant (363.6)						
69. Total Other storage Plant						
70. Base Load Liquefied natural Gas Terminaling and Processing Plant						
71. Land and Land Rights (364.1)						
72. Structures and Improvements (364.2)						
73. LNG Processing Terminal Equipments (364.3)						
74. LNG Transportation Equipment (364.4)						
75. Measuring and Regulating Equipment (364.5)						
76. Compressor Station Equipment (364.6)						
77. Communications Equipment (364.7)						
78. Other Equipment (364.8)						
79. Asset Retirement Costs for Base Load Liquefied Natual Gas Terminaliing and Processing Plant (364.9)						

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Gas Plant in Service - Storage and Processing (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
80. Total Base Load Liquefied Nat`l Gas, Terminal and Processing Plant						
76. Total Nat`l Gas Storage and Processing Plant (57,69,80)	$94,535,384.00	$3,019,283.00	($971,376.00)	$0.00	$0.00	$96,583,291.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Plant in Service - Transmission,Distribution and General (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
TRANSMISSION PLANT						
83. Land and Land Rights (365.1)						
84. Rights-of-Way (365.2)	$220,660.00	$0.00	$0.00	$0.00	$0.00	$220,660.00
85. Structures and Improvements (366)						
86. Mains (367)	$25,049,695.00	$6,518,141.00	($8,668.00)	$0.00	$0.00	$31,559,168.00
87. Compressor Station Equipment (368)						
88. Measuring and Regulating Sstation Equipment (369)						
89. Communication Equipment (370)						
90. Other Equipment (371)						
91. Asset Retirement Costs for Transmission Plant (372)	$4,061,651.00	$0.00	($90,574.00)	$0.00	$0.00	$3,971,077.00
92. Total Transmission Plant	$29,332,006.00	$6,518,141.00	($99,242.00)	$0.00	$0.00	$35,750,905.00
DISTRIBUTION PLANT ( )						
94. Land and Land Rights (374)	$133,742.00	$0.00	$0.00	$0.00	$0.00	$133,742.00
95. Structures and Improvements (375)	$850,248.00	$53,474.00	($3,911.00)	$0.00	$0.00	$899,811.00
96. Mains (376)	$334,536,533.00	$20,847,236.00	($2,785,051.00)	$0.00	($438,340.00)	$352,160,378.00
97. Compressor Station Equipment (377)						
98. Measuring and Regulating Station Equipment - General (378)	$15,373,535.00	$789,640.00	($1,838,099.00)	$0.00	$0.00	$14,325,076.00
99. Measuring and Regulating Station Equipment - City Gate (379)	$4,922,327.00	$755,385.00	($277,751.00)	$0.00	$0.00	$5,399,961.00
100. Services (380)	$208,930,079.00	$39,595,421.00	($3,696,998.00)	$0.00	$438,340.00	$245,266,842.00
101. Meters (381)	$42,251,661.00	$2,402,746.00	($48,974.00)	$0.00	$0.00	$44,605,433.00

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Gas Plant in Service - Transmission,Distribution and General (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
102. Meter Installations (382)						
103. House Regulators (383)	$24,915,272.00	$20,576.00	$0.00	$0.00	$0.00	$24,935,848.00
104. House Regulator Installations (384)						
105. Industrial Measuring and Regulating Station Equipment (385)	$944,325.00	$0.00	$0.00	$0.00	$0.00	$944,325.00
106. Other Property on Customers Premises (386)						
107. Other Equipment (387)	$72,572.00	($21,460.00)	$0.00	$0.00	$0.00	$51,112.00
108. Asset Retirement Costs for Distribution Plant (388)	$12,302,034.00	$0.00	($183,449.00)	$0.00	$0.00	$12,118,585.00
109. Total Distribution Plant	$645,232,328.00	$64,443,018.00	($8,834,233.00)	$0.00	$0.00	$700,841,113.00
GENERAL PLANT						
111. Land and Land Rights (389)						
112. Structures and Improvements (390)						
113. Office Furniture and Equipment (391)						
114. Transportation Equipment (392)	$1,765,047.00	$31,079.00	($80,757.00)	$0.00	$0.00	$1,715,369.00
115. Stores Equipment (393)						
116. Tools, Shop and garage Equipment (394)	$4,908,393.00	$242,316.00	$0.00	$0.00	$0.00	$5,150,709.00
117. Laboratory Equipment (395)						
118. Power Operated Equipment (396)	$2,581,940.00	$20,869.00	($10,345.00)	$0.00	$0.00	$2,592,464.00
119. Communication Equipment (397)	$18,841.00	($1,762.00)	$0.00	$0.00	$0.00	$17,079.00
120. Miscellaneous equipment (398)						

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Plant in Service - Transmission,Distribution and General (Ref Page: 206)

	Bal Beg Yr (b)	Addition (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Bal End Yr (g)
121. Subtotal (Lines 104-113)	$9,274,221.00	$292,502.00	($91,102.00)	$0.00	$0.00	$9,475,621.00
122. Other Tangible Property (399)						
123. Asset Retirement Costs for General Plant (399.1)	$0.00					
124. Total General Plant (Lines 121,122 and 123)	$9,274,221.00	$292,502.00	($91,102.00)	$0.00	$0.00	$9,475,621.00
125. Total Accounts 101 and 106	$778,374,326.00	$74,272,944.00	($9,995,953.00)	$0.00	$0.00	$842,651,317.00
126. Gas Plant Purchased	$0.00					
127. (Less) Gas Plant Sold						
128. Experimental Gas Plant Unclassified						
Total Gas Plant in Service (Lines 125-128)	$778,374,326.00	$74,272,944.00	($9,995,953.00)	$0.00	$0.00	$842,651,317.00

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

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Construction Work in Progress - (Acct 107) (Ref Page: 216)

	Project (a)	Construction WIP (b)	Est Add Cost
	UNDERGROUND STORAGE	$0.00	$0.00
	GAS COMPRESSOR REPLACEMENT/ADDITION	$29,122,823.00	$142,971.00
	DRILL WELLS IN CENTER FIELD	$1,772,436.00	$165,677.00
	UNDERGROUND STORAGE MINOR	$6,380,683.00	$5,010,777.00
	0	$0.00	$0.00
	TRANSMISSION	$0.00	$0.00
	PENILE TO PADDY'S RUN PIPELINE	$4,044,614.00	$15,121.00
	REPLACE STEEL PIPELINE WKY TRANSMISSION	$2,489,084.00	$1,273,361.00
	REPLACE PIPE ON WESTERN KY LINE	$2,189,145.00	$837,109.00
	TRANSMISSION MINOR	$2,816,392.00	$6,785,625.00
	0	$0.00	$0.00
	DISTRIBUTION	$0.00	$0.00
	PENILE CITY GATE STATION REDESIGN	$1,154,178.00	$443,518.00
	DISTRIBUTION MINOR	$4,711,181.00	$2,228,532.00
	0	$0.00	$0.00
	GENERAL PLANT	$0.00	$0.00
	GENERAL PLANT MINOR	$674,187.00	$135,164.00
TOTAL		$55,354,723.00	$17,037,855.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

General Description of Construction Overhead Procedure - Components of Formulat (Ref Page: 218)

	Amount (b)	Capitalization Ration (Percent) (c)	Cost Rate Percentage (d)
Please include all notes requested for construction overhead with the hard copy.			
Uppercase Vars (S,D,P,C,W) fall under Amount (b) column		0	0
Lowercase Vars (s,d,p,c) fall under Cost Rate Percentage (d) column			
1. Components of Formula (Derived from actual book balances and actual cost rates)			
Average Short-Term Debt (Var S)			
Short-Term Interest (Var s)			0
Long Term Debt (Vars D and d)		0	0
Preferred Stock (Vars P and p)		0	0
Common Equity (Vars C and c)		0	0
Total Capitalization			
Average Construction Work in Progress Balance (Var W)		0	0
2. Gross Rate for Borrowed Funds s(S/W) + d[(D/(D+P+C))(1-(S/W)]			
3. Rate for Other Funds [1-(S/W)][p(P/D+P+C)) + c(C/(D+P+C))]			
4. Weighted Average Rate Actually Used for the Year:			
a. Rate for Borrowed Funds			0
b. Rate for Other Funds			0

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

General Description of Construction Overhead Procedure - Components of Formulat (Ref Page: 218) - NOTES

LOCAL ENGINEERING:

Salaries and expenses of Generation Services Department, Energy Delivery Department and Gas Department personnel engaged in construction work, but not assignable to a particular work order (“WO”), are charged to engineering clearing WOs which have been set up in a clearing account for each department. Examples of such charges are: work with the construction budget, cost of estimating, construction work, preparation of field reports, conferences on construction matters and general supervision of construction projects.

Each month the costs accumulated in these clearing WOs are allocated to specific WOs coming under the direct supervision of the depts. The WOs are spread based on total direct cost of WOs.

The labor and expenses of engineers and foremen who are directly assigned to a particular WO are charged to that WO.

SERVICE CONTRACT CHARGES:

These expenses are charged directly to construction and other projects based on service performed.

EMPLOYEE BENEFITS:

Vacation, holiday, sick and other off-duty payments, hospitalization, dental, group life insurance and pension costs, are charged to construction based on the ratio of direct labor charged to construction to the total direct labor.

ADMINISTRATIVE AND GENERAL EXPENSES:

The allocation of administrative and general expenses to construction is based on a study of the estimated time engaged in construction activities by persons and departments charging time to FERC Account 920. The administrative and general salaries and expenses (FERC 920-921) applicable to construction are allocated to all construction WOs on the basis of total direct costs.

Note:

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC):

LG&E does not capitalize AFUDC for gas utility plant.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Accumulated Provision for Depreciation of Gas Utility Plant (Acct 108) (Ref Page: 219)

Description		Total (b)	Gas Plant In Service (c)	Held for Future (d)	Leased (e)
A. BALANCES AND CHANGES DURING YEAR					
Balance beginning of Year		$249,178,162.00	$249,178,162.00	$0.00	$0.00
Depreciation Provisions for Year, Charged to					
Depreciation Expense (403)		$20,608,305.00	$20,608,305.00	$0.00	$0.00
Depreciation Expense for Asset Retirement Costs (403.1)					
Expense of Gas Plant Leased to Others (413)					
Transportation Expenses - Clearing		$70,963.00	$70,963.00	$0.00	$0.00
Other Clearing Accounts					
Other Clearing (Specify)	0	($14,150.00)	($14,150.00)	$0.00	$0.00
Total Deprec. Prov. for Year		$20,665,118.00	$20,665,118.00	$0.00	$0.00
Net Charges for Plant Retired					
Book Cost of Plant Retired		$9,995,953.00	$9,995,953.00	$0.00	$0.00
Cost of Removal		$1,769,204.00	$1,769,204.00	$0.00	$0.00
Salvage (Credit)		$4,741.00	$4,741.00	$0.00	$0.00
Total Net Chrgs for Plant Ret		$11,760,416.00	$11,760,416.00	$0.00	$0.00
Other Debit or Credit Items (Describe)					
	0	$3,046,833.00	$3,046,833.00	$0.00	$0.00
Balance at End of Year		$261,129,697.00	$261,129,697.00	$0.00	$0.00
B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS					
Productions - Manufactured Gas					
Prodcution of Gathering-Natural Gas					
Products Extraction - Natural Gas					
Underground Gas Storage		$34,297,314.00	$34,297,314.00	$0.00	$0.00
Other Storage Plant					

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Accumulated Provision for Depreciation of Gas Utility Plant (Acct 108) (Ref Page: 219)

Description	Total (b)	Gas Plant In Service (c)	Held for Future (d)	Leased (e)
Base Load LNG Terminaling and Processing Plant				
Transmision	$11,555,351.00	$11,555,351.00	$0.00	$0.00
Distribution	$210,147,087.00	$210,147,087.00	$0.00	$0.00
General	$5,129,945.00	$5,129,945.00	$0.00	$0.00
Total	$261,129,697.00	$261,129,697.00	$0.00	$0.00

Note:

Other Clearing (Specific) - Accrual for cost of removal and salvage for ARO parent assets (FERC 254 and 403)	$ (14,150)

Other Debit or Credit Items - The balance for the accrual for Cost of Removal and Salvage for ARO parent assets was reclassed from Other Regulatory Liabilities (254) to Accumulated Provision for Depreciation (108)	$ 2,189,707
Accrual for depreciation on asset retirement costs (Other Regulatory Assets FERC 182.3)	733,380
Customer payments related to construction projects	123,746

	$ 3,046,833

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Stored Accounts (Lines 1-5) (Ref Page: 220)

	117.1 (b)	117.2 (c)	117.3 (d)	117.4 (e)	164.1 (f)	164.2 (g)	164.3 (h)	Total (I)
Balance at Beginning of Year	$2,139,990.00	$0.00	$0.00	$0.00	$42,010,154.00	$0.00	$0.00	$44,150,144.00
Gas delivered to Storage	$0.00	$0.00	$0.00	$0.00	$52,239,510.00	$0.00	$0.00	$52,239,510.00
Gas Withdrawn from Storage	$0.00	$0.00	$0.00	$0.00	$46,702,776.00	$0.00	$0.00	$46,702,776.00
Other Debits and Credits								
Balance at End of Year	$2,139,990.00	$0.00	$0.00	$0.00	$47,546,888.00	$0.00	$0.00	$49,686,878.00

Note:
Gas Withdrawn from Storage, Column (f) includes $1,735,363 for 440,383 Mcf of gas lost in storage operations charged to Gas Losses (823).

Non-current gas in Column (b) consists of recoverable base gas. Current gas in Column (f) consists of working gas.

The weighted average cost inventory method is used to report gas stored underground.

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Gas Stored Accounts (Lines 6-7) (Ref Page: 220)

	117.1 (b)	117.2 (c)	117.3 (d)	117.4 (e)	164.1 (f)	164.2 (g)	164.3 (h)	Total (I)
MCF	$2,930,000.00	$0.00	$0.00	$0.00	$11,558,382.00	$0.00	$0.00	$14,488,382.00
Amount Per MCF	$0.73	$0.00	$0.00	$0.00	$4.11	$0.00	$0.00	$3.43

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Investments (123,124,136) (Ref Page: 222)

	Description of Investment (a)	(b)	Book Cost at Beginning of	Purchases or Additions (d)	Sales of Other Dispositions
Investments in Associated Companies (123)					
(123)					
Other Investments (124)					
(124)					
Temporary Case Investments (136)					
(136)	Goldman Sachs Financial Square Fed		$0.00	$8,500,000.00	$8,497,000.00
(136)	Goldman Sachs Financial Square Fed		$347,817.00	$137,828,000.00	$138,162,730.00
(136)	JPMorgan Fund		$1,096,467.00	$181,152,000.00	$182,240,000.00
(136)	Fidelity Fund		$12,784,626.00	$195,194,000.00	$207,959,683.00
(136)	UBS Fund		$87,691.00	$197,722,000.00	$193,331,501.00
(136)	Money Pool		$0.00	$515,000.00	$515,000.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Investments (123,124,136) (Ref Page: 222) (Part Two)

	Description of Investment (a)	Principal Amt or No of	Book Cost End of Year (g)	Revenues for Year (h)	Gain or Loss (i)
Investments in Associated Companies (123)					
(123)					
Other Investments (124)					
(124)					
Temporary Case Investments (136)					
(136)	Goldman Sachs Financial Square Fed	$0.00	$3,007.00	$7.00	$0.00
(136)	Goldman Sachs Financial Square Fed	$0.00	$13,936.00	$849.00	$0.00
(136)	JPMorgan Fund	$0.00	$11,911.00	$3,444.00	$0.00
(136)	Fidelity Fund	$0.00	$21,751.00	$2,808.00	$0.00
(136)	UBS Fund	$0.00	$4,483,758.00	$5,568.00	$0.00
(136)	Money Pool	$0.00	$0.00	$0.00	$0.00

Note:
Revenues for Year include Dividend Income from Investments.

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Investments in Subsidiary Companies (123.1) (Ref Page: 224)

	Description	Date Acquired (b)	Date Maturity (c)	Investment Beg of Yr. (d)	Equity in Subsidiary (e)	Revenues (f)	Investment End Yr (g)	Invest Disposed of (h)
	Ohio Valley Electric Corporation (5.63%)			$0.00	$0.00	$56,300.00	$0.00	$0.00
	Common Stock $100 par value, 5,630 shares			$0.00	$0.00	$0.00	$0.00	$0.00
	700 shares	11/18/1952		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	700 shares	01/08/1953		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	700 shares	02/25/1953		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	700 shares	04/10/1953		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	700 shares	05/12/1953		$70,000.00	$0.00	$0.00	$70,000.00	$0.00
	1400 shares	07/27/1953		$140,000.00	$0.00	$0.00	$140,000.00	$0.00
	730 shares	03/04/2005		$104,286.00	$0.00	$0.00	$104,286.00	$0.00
TOTAL				$594,286.00	$0.00	$56,300.00	$594,286.00	$0.00

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Prepayments (Ref Page: 230)

	Balance at End of Year
Prepaid Insurance	$2,383,112.00
Prepaid Rents	$37,660.00
Prepaid Taxes	$1,158,110.00
Prepaid Interest	$0.00
Miscellaneous Prepayments	$1,546,788.00
Total	$5,125,670.00

Note:
The Miscellaneous Prepayments line is comprised of Tennessee Valley Authority $459,052, Open Systems International $71,290, Gas for Combustion Turbines $187,596, Rights of Way $200,000, Risk Management $90,500, IT Contracts $30,784, EPIS, Inv. $10,640, NERC $75,952, Doble $18,251, Siemens Energy $35,021, RAPID Renewal $39,200, EEI Dues $267,458 and LG&E Center $61,044.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Extraordinary Property Losses (182.1) (Ref Page: 230)

Description	Balance Beg Yr (b)	Total Loss (b)	Losses During Yr	Acct (d)	Written Off (e)	Balance (f)
0	$0.00	$0.00	$0.00		$0.00	$0.00
TOTAL	$0.00	$0.00			$0.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Unrecovered Plant and Regulatory Study costs (182.2) (Ref Page: 230)

	Description	Balance Beg Yr (b)	Total Loss (b)	Losses During Yr	Acct (d)	Written Off (e)	Balance (f)
	0	$0.00	$0.00	$0.00	0	$0.00	$0.00
TOTAL		$0.00	$0.00		0	$0.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Other Regulatory Assets (Acct 182.3) (Ref Page: 232)

Description and Purpose	Bal Beg Yr (b)	Debits (c)	Written Off Acct (d)	Written Off Amt (e)	Balance End Yr (f)
ASC 715 - Pension and Postretirement	$231,705,649.00	$23,775,059.00	184	$91,392,827.00	$164,087,881.00
Asset Retirement Obligation - Electric	$13,010,367.00	$6,705,785.00	230/407.4	$1,685,805.00	$18,030,347.00
Wind Storm 2008 (Aug-10 to Jul-20)	$17,851,419.00	$0.00	593	$2,354,033.00	$15,497,386.00
ASC 740 - Income Taxes	$14,322,583.00	$166,627.00	282/283	$431,860.00	$14,057,350.00
MISO Exit Fee	$9,798.00	$0.00	440-445	$9,798.00	$0.00
Asset Retirement Obligation - Gas	$1,998,031.00	$1,903,745.00	230/407.4	$996,849.00	$2,904,927.00
Asset Retirement Obligation - Common	$17,227.00	$8,277.00	230/407.4	$506.00	$24,998.00
KY Consortium - Carbon Storage (Aug-10 to Jul-14)	$347,557.00	$0.00	930.2/146	$219,510.00	$128,047.00
Winter Storm 2009-Gas/Elec (Aug-10 to Jul-20)	$33,244,114.00	$0.00	571/593/880	$4,383,839.00	$28,860,275.00
Environmental Cost Recovery	$631,535.00	$2,318,727.00	440-445	$789,551.00	$2,160,711.00
Performance-Based Rates	$5,639,885.00	$1,556,141.00	803	$4,621,995.00	$2,574,031.00
EKPC FERC Transmission (Mar-09 to Feb-14)	$197,834.00	$0.00	456/566	$169,572.00	$28,262.00
0	$0.00	$0.00	0	$0.00	$0.00
0	$0.00	$0.00	0	$0.00	$0.00
Carbon Mgmt Research Group (Aug-10 to Jul-20)	$154,470.00	$199,620.00	930.2	$219,180.00	$134,910.00
Fuel Adjustment Clause	$6,068,000.00	$9,635,000.00	440-445	$14,011,000.00	$1,692,000.00
Gas Supply Clause	$5,439,239.00	$11,936,838.00	803/254	$10,016,432.00	$7,359,645.00
Long-Term Interest Rate Swap	$58,605,484.00	$9,315,823.00	244/245	$32,008,386.00	$35,912,921.00
Coal Contracts (Nov-10 to Dec-15)	$1,671,497.00	$0.00	253	$925,578.00	$745,919.00
Swap Termination (Aug-10 to Apr-35)	$8,678,746.00	$0.00	930.2	$388,660.00	$8,290,086.00
0	$0.00	$0.00	0	$0.00	$0.00
Rate Case Expense - Electric (Aug-10 to Jul-13)	$163,236.00	$0.00	928	$163,236.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Other Regualatory Assets (Acct 182.3) (Ref Page: 232)

	Description and Purpose	Bal Beg Yr (b)	Debits (c)	Written Off Acct (d)	Written Off Amt (e)	Balance End Yr (f)
	Rate Case Expense - Gas (Aug-10 to Jul-13)	$93,416.00	$0.00	928	$93,416.00	$0.00
	Unamortized Debt Expense (Aug-10 to Apr-35)	$3,294,619.00	$0.00	181	$186,562.00	$3,108,057.00
	Summer Storm 2011 (Jan-13 to Dec-17)	$8,052,125.00	$0.00	593	$1,610,425.00	$6,441,700.00
	General Mgmt Audit - Electric (Jan-13 to Dec-15)	$91,583.00	$0.00	928	$30,528.00	$61,055.00
	General Mgmt Audit - Gas (Jan-13 to Dec-15)	$29,825.00	$0.00	928	$9,943.00	$19,882.00
	DSM Cost Recovery - Under-recovery	$930,885.00	$7,491,371.00	440-445	$4,818,123.00	$3,604,133.00
	Rate Case Expense - Electric (Jan-13 to Dec-15)	$894,413.00	$26,576.00	928	$324,638.00	$596,351.00
	Rate Case Expense - Gas (Jan-13 to Dec-15)	$284,806.00	$8,475.00	928	$103,386.00	$189,895.00
Total		$413,428,343.00	$75,048,064.00		$171,965,638.00	$316,510,769.00

Note:
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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Miscellaneous Deferred Debits (Acct 186) (Ref Page: 233)

	Description (a)	Bal Beg Yr (b)	Debits (c)	CR Acct (d)	CR Amt (e)	Bal End Yr (c)
	Goodwill	$389,157,352.00	$0.00	0	$0.00	$389,157,352.00
	OVEC Power Purchase Contract (Nov-10 to Mar-26)	$74,923,412.00	$0.00	254	$5,540,496.00	$69,382,916.00
	Coal Contracts (Nov-10 to Dec-16)	$61,371,353.00	$0.00	254	$18,657,374.00	$42,713,979.00
	Valuation of SO2 Allowances (Nov-10 to Dec-40)	$1,763,404.00	$0.00	254	$221,045.00	$1,542,359.00
	Customer Credit Accounts Receivable	$254,531.00	$348,073.00	0	$0.00	$602,604.00
	Financing Expense	$836.00	$225,971.00	0	$0.00	$226,807.00
	Cellular Antenna Billable Charges	$119,450.00	$502,495.00	107/108/143	$519,012.00	$102,933.00
Misc. Work in Progress		$0.00	$0.00		$0.00	$0.00
Total		$527,590,338.00	$1,076,539.00		$24,937,927.00	$503,728,950.00

Note:
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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Accumulated Deferred Income Taxes (Acct 190) (Ref Page: 234)

Description	Bal Beg Yr	Amt 410.1 (c)	Amt 411.1 (d)	Amt 410.2 (e)	Amt 411.2 (f)
Account 190					
Electric	$139,411,775.00	$41,093,295.00	$34,532,584.00	$0.00	$0.00
Gas	$23,876,375.00	$9,766,344.00	$6,048,305.00	$0.00	$0.00
Other (Define)	$218,810.00	$0.00	$0.00	$982.00	$19,162.00
Total	$163,506,960.00	$50,859,639.00	$40,580,889.00	$982.00	$19,162.00
Other (Specify)					
TOTAL Acct 190	$163,506,960.00	$50,859,639.00	$40,580,889.00	$982.00	$19,162.00
Classification of TOTAL					
Federal INcome TAx	$136,961,552.00	$41,574,525.00	$31,773,317.00	$982.00	$16,358.00
State Income Tax	$26,545,408.00	$9,285,114.00	$8,807,572.00	$0.00	$2,804.00
Local Income Tax					

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Accumulated Deferred Income Taxes (Acct 190) (Ref Page: 234) (Part Two)

Description	Debit Adj Acct (g)	Debit Amount (h)	Credit Acct (i)	Credit Amount (j)	Balance End Yr (k)
Account 190					
Electric	283	$19,871,683.00	254/283	$2,853,040.00	$149,869,707.00
Gas	283	$4,805,567.00	254/283	$266,103.00	$24,697,800.00
Other (Define)		$0.00		$0.00	$236,990.00
Total		$24,677,250.00		$3,119,143.00	$174,804,497.00
Other (Specify)					
TOTAL Acct 190		$24,677,250.00		$3,119,143.00	$174,804,497.00
Classification of TOTAL					
Federal INcome TAx		$21,065,945.00		$2,832,995.00	$145,408,670.00
State Income Tax		$3,611,305.00		$286,148.00	$29,395,827.00
Local Income Tax					

Note:
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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Capital Stock (Accounts 201 and 204) (Ref Page: 250)

	Class, Series and Name of	Num Shares Auth (b)	Par or Stated Val (c)	Call Price (d)	Outstanding Shares (e)
Common Stock					
	Without Par Value	75,000,000	$0.00	$0.00	$21,294,223.00
Total Common Stock		75,000,000	$0.00	$0.00	$21,294,223.00
Preferred Stock					
	$25 Par Value	1,720,000	$0.00	$0.00	$0.00
	Without Par Value	6,750,000	$0.00	$0.00	$0.00
Total Preferred Stock		8,470,000	$0.00	$0.00	$0.00
TOTAL Capital Stock		83,470,000	$0.00	$0.00	$21,294,223.00
Other					

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Capital Stock (Accounts 201 and 204) (Ref Page: 250) (Part Two)

	Class, Series and Name	Outstanding Amt (f)	Num Held Rqd 217 (g)	Cost Held Rqd 217 (h)	Num Held Sinking (i)	Num Held Amount (j)
Common Stock						
	Without Par Value	$425,170,424.00	0	$0.00	0	$0.00
Total Common Stock		$425,170,424.00	0	$0.00	0	$0.00
Preferred Stock						
	$25 Par Value	$0.00	0	$0.00	0	$0.00
	Without Par Value	$0.00	0	$0.00	0	$0.00
Total Preferred Stock		$0.00	0	$0.00	0	$0.00
TOTAL Capital Stock		$425,170,424.00	0	$0.00	0	$0.00
Other						

Note:
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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Page: 252)

Description (a)	* (b)	Shares (c)	Amount (d)
Capital Stock Subscribed (202,205)			
Not applicable for LG&E		0	$0.00
Total Capital Stock Subscribed			
Stock Liability for Conversion (203,206)			
Not applicable for LG&E		0	$0.00
Total Stock Liability for Conversion			
Premium on Capital Stock (207)			
Not applicable for LG&E		0	$0.00
Total Premium on Capital Stock (207)			
Installments Received on Capital Stock (212)			
Not applicable for LG&E		0	$0.00
Total Installments Received on Capital Stock (212)			

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Other Paid-In Capital (208-211) (Ref Page: 253)

	Item (a)	Amount (b)
(a) Donations Received from Stockholders (208)		
Total (208)		
(b) Reduction in Par or Stated Value (209)		
Total (209)		
(c) Gain or Resale or Cancellation of Reacquired Capital Stock (210)		
Total (210)		
(d) Miscellaneous Paid-In Capital (211)		
	Contributed Capital - Balance January 1, 2013	$1,277,667,368.00
	Contributed Capital March 31, 2013	$25,000,000.00
	Contributed Capital June 30, 2013	$29,000,000.00
	Contributed Capital December 31, 2013	$32,000,000.00
Total (211)		$1,363,667,368.00
Total Accts 208-211		$1,363,667,368.00

Note:
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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Discount on Capital Stock (Act 213) (Ref Page: 254)

	Class and Series (a)	Balance End Yr (b)
	0	0.0000
TOTAL		0.0000

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Capital Stock Expense (Act 214) (Ref Page: 254)

	Class and Series (a)	Balance End Yr (b)
	Expenses on Common Stock	$835,889.00
TOTAL		$835,889.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Long-Term Debt (221,222,223 and 224) (Ref Page: 256)

	Class Series and Name (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (d)	Interest Rate in % (e)
Acct 221 Bonds					
(221)	Pollution Control Bonds:			$0.00	0.0000
(221)	Jefferson Co. 2000 Series A, due 05/01/2027, Var	05/19/2000	05/01/2027	$25,000,000.00	0.0000
(221)	Trimble Co. 2000 Series A, due 08/01/2030, Var	08/09/2000	08/01/2030	$83,335,000.00	0.0000
(221)	Jefferson Co. 2001 Series A, due 09/01/2027, Var	09/11/2001	09/01/2027	$10,104,000.00	0.0000
(221)	Jefferson Co. 2001 Series A, due 09/01/2026, Var	03/06/2002	09/01/2026	$22,500,000.00	0.0000
(221)	Trimble Co. 2001 Series A, due 09/01/2026, Var	03/06/2002	09/01/2026	$27,500,000.00	0.0000
(221)	Jefferson Co. 2001 Series B, due 11/01/2027, Var	03/22/2002	11/01/2027	$35,000,000.00	0.0000
(221)	Trimble Co. 2001 Series B, due 11/01/2027, Var	03/22/2002	11/01/2027	$35,000,000.00	0.0000
(221)	Trimble Co. 2002 Series A, due 10/01/2032, Var	10/23/2002	10/01/2032	$41,665,000.00	0.0000
(221)	Louisville Metro 2003A, due 10/01/2033, 1.650%	11/20/2003	10/01/2033	$128,000,000.00	1.6500
(221)	Louisville Metro 2005A, due 02/01/2035, 2.200%	04/13/2005	02/01/2035	$40,000,000.00	2.2000
(221)	Trimble Co. 2007 Series A, due 06/01/2033, 4.600%	04/26/2007	06/01/2033	$60,000,000.00	4.6000
(221)	Louisville Metro 2007A, due 06/01/2033, 1.150%	04/26/2007	06/01/2033	$31,000,000.00	1.1500
(221)	Louisville Metro 2007B, due 06/01/2033, 1.600%	04/26/2007	06/01/2033	$35,200,000.00	1.6000
(221)	Interest Rate Swaps:			$0.00	0.0000
(221)	First Mortgage Bonds:			$0.00	0.0000
(221)	2010 due 11/15/2015, 1.625%	11/16/2010	11/15/2015	$250,000,000.00	1.6250
(221)	2010 due 11/15/2040, 5.125%	11/16/2010	11/15/2040	$285,000,000.00	5.1250
(221)	2013 due 11/15/2043, 4.650%	11/15/2013	11/15/2043	$250,000,000.00	4.6500
Total (221)				$1,359,304,000.00	
Acct 222 Reacquired Bonds					

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Long-Term Debt (221,222,223 and 224) (Ref Page: 256)

	Class Series and Name (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (d)	Interest Rate in % (e)
(222)					0
Total (222)					
Acct 223 Advances from Associated Companies					
(223)					0
Total (223)					
Acct 224 Other Long Term Debt					
(224)	Purchase Accounting Adjustments for Fair Value			$0.00	0.0000
(224)	Louisville Metro 2007A, due 06/01/2033, 1.150%			$0.00	1.1500
(224)	Trimble Co. 2007 Series A, due 06/01/2033, 4.600%			($1,773,437.00)	4.6000
(224)	Jefferson Co. 2000 Series A, due 05/01/2027, Var			$0.00	0.0000
(224)	Louisville Metro 2005A, due 02/01/2035, 2.200%			$0.00	2.2000
Total (224)				($1,773,437.00)	

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Long-Term Debt (221,222,223 and 224) (Ref Page: 256) (Part Two)

	Class Series and Name (a)	Interest Amount (f)	Held - Reaquired Bonds	Held - Sinking and Other	Redemption Price Per $100
Acct 221 Bonds					
(221)	Pollution Control Bonds:	$0.00	$0.00	$0.00	$0.00
(221)	Jefferson Co. 2000 Series A, due 05/01/2027, Var	$199,817.00	$0.00	$0.00	$0.00
(221)	Trimble Co. 2000 Series A, due 08/01/2030, Var	$120,604.00	$0.00	$0.00	$0.00
(221)	Jefferson Co. 2001 Series A, due 09/01/2027, Var	$13,859.00	$0.00	$0.00	$0.00
(221)	Jefferson Co. 2001 Series A, due 09/01/2026, Var	$52,995.00	$0.00	$0.00	$0.00
(221)	Trimble Co. 2001 Series A, due 09/01/2026, Var	$62,333.00	$0.00	$0.00	$0.00
(221)	Jefferson Co. 2001 Series B, due 11/01/2027, Var	$125,390.00	$0.00	$0.00	$0.00
(221)	Trimble Co. 2001 Series B, due 11/01/2027, Var	$124,437.00	$0.00	$0.00	$0.00
(221)	Trimble Co. 2002 Series A, due 10/01/2032, Var	$70,271.00	$0.00	$0.00	$0.00
(221)	Louisville Metro 2003A, due 10/01/2033, 1.650%	$2,112,000.00	$0.00	$0.00	$0.00
(221)	Louisville Metro 2005A, due 02/01/2035, 2.200%	$2,183,167.00	$0.00	$0.00	$0.00
(221)	Trimble Co. 2007 Series A, due 06/01/2033, 4.600%	$2,760,000.00	$0.00	$0.00	$0.00
(221)	Louisville Metro 2007A, due 06/01/2033, 1.150%	$248,603.00	$0.00	$0.00	$0.00
(221)	Louisville Metro 2007B, due 06/01/2033, 1.600%	$563,200.00	$0.00	$0.00	$0.00
(221)	Interest Rate Swaps:	$7,895,241.00	$0.00	$0.00	$0.00
(221)	First Mortgage Bonds:	$0.00	$0.00	$0.00	$0.00
(221)	2010 due 11/15/2015, 1.625%	$4,062,500.00	$0.00	$0.00	$0.00
(221)	2010 due 11/15/2040, 5.125%	$14,606,250.00	$0.00	$0.00	$0.00
(221)	2013 due 11/15/2043, 4.650%	$1,311,449.00	$0.00	$0.00	$0.00
Total (221)		$36,512,116.00	$0.00	$0.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Long-Term Debt (221,222,223 and 224) (Ref Page: 256) (Part Two)

	Class Series and Name (a)	Interest Amount (f)	Held - Reaquired Bonds	Held - Sinking and Other	Redemption Price Per $100
Acct 222 Reacquired Bonds					
(222)					
Total (222)					
Acct 223 Advances from Associated Companies					
(223)					
Total (223)					
Acct 224 Other Long Term Debt					
(224)	Purchase Accounting Adjustments for Fair Value	$0.00	$0.00	$0.00	$0.00
(224)	Louisville Metro 2007A, due 06/01/2033, 1.150%	($2,442,831.00)	$0.00	$0.00	$0.00
(224)	Trimble Co. 2007 Series A, due 06/01/2033, 4.600%	$91,336.00	$0.00	$0.00	$0.00
(224)	Jefferson Co. 2000 Series A, due 05/01/2027, Var	($1,213,664.00)	$0.00	$0.00	$0.00
(224)	Louisville Metro 2005A, due 02/01/2035, 2.200%	($4,134,536.00)	$0.00	$0.00	$0.00
Total (224)		($7,699,695.00)	$0.00	$0.00	$0.00

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Unamortized Debt Expense (181,225,226) (Ref Page: 258)

	Designation of Long-Term	Principal Amount of Debt	Total Expense Premium or	Amortization Period From (d)	Amortization Period To (e)
Acct 181					
(181)	Unamortized Debt Expense:	$0.00	$0.00		
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)	Jefferson Co. 2001 Series A, due 09/01/2027, Var	$10,104,000.00	$526,085.00	09/11/2001	09/01/2027
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)	Trimble Co. 2000 Series A, due 08/01/2030, Var	$83,335,000.00	$1,154,826.00	08/09/2000	08/01/2030
(181)	Jefferson Co. 2001 Series A, due 09/01/2026, Var	$22,500,000.00	$242,653.00	03/06/2002	09/01/2026
(181)	Trimble Co. 2001 Series A, due 09/01/2026, Var	$27,500,000.00	$263,855.00	03/06/2002	09/01/2026
(181)	Jefferson Co. 2001 Series B, due 11/01/2027, Var	$35,000,000.00	$281,244.00	03/22/2002	11/01/2027
(181)	Trimble Co. 2001 Series B, due 11/01/2027, Var	$35,000,000.00	$281,283.00	03/22/2002	11/01/2027
(181)	Trimble Co. 2002 Series A, due 10/01/2032, Var	$41,665,000.00	$1,112,006.00	10/23/2002	10/01/2032
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)		$0.00	$0.00		
(181)	Trimble Co. 2007 Series A, due 06/01/2033, 4.600%	$60,000,000.00	$1,239,280.00	04/26/2007	06/01/2033
(181)	FMB 2010 due 11/15/2015, 1.625%	$250,000,000.00	$2,563,689.00	11/16/2010	11/15/2015
(181)	FMB 2010 due 11/15/2040, 5.125%	$285,000,000.00	$3,570,026.00	11/16/2010	11/15/2040
(181)	Revolving Credit Facility	$0.00	$5,509,317.00	11/01/2010	12/31/2017
(181)	Purchase Accounting Adjustment	$0.00	($3,698,836.00)	11/01/2010	12/31/2014
(181)	Louisville Metro 2003A, due 10/01/2033, 1.650%	$128,000,000.00	$4,792,737.00	11/20/2003	10/01/2033

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Unamortized Debt Expense (181,225,226) (Ref Page: 258)

	Designation of Long-Term	Principal Amount of Debt	Total Expense Premium or	Amortization Period From (d)	Amortization Period To (e)
(181)	Louisville Metro 2007B, due 06/01/2033, 1.600%	$35,200,000.00	$1,085,694.00	04/26/2007	06/01/2033
(181)	Louisville Metro 2000 Series A, due 05/01/2027, Va	$25,000,000.00	$883,831.00	05/19/2000	05/01/2027
(181)	Louisville Metro 2005A, due 02/01/2035, 2.200%	$40,000,000.00	$1,428,142.00	04/13/2005	02/01/2035
(181)	Louisville Metro 2007A, due 06/01/2033, 1.150%	$31,000,000.00	$938,023.00	04/26/2007	06/01/2033
(181)	FMB 2013 due 11/15/2043, 4.650% (Case 2012-00233 8	$250,000,000.00	$2,611,393.00	11/14/2013	11/15/2043
(181)	S-3 SEC Shelf Registration	$0.00	$6,667.00	03/28/2012	03/27/2015
Total (181)		$1,359,304,000.00	$24,791,915.00		
Acct 225					
(225)					
Total (225)					
Acct 226					
(226)	Unamortized Debt Discount:	$0.00	$0.00		
(226)	FMB 2010 due 11/15/2015, 1.625%	$250,000,000.00	$882,500.00	11/16/2010	11/15/2015
(226)	FMB 2010 due 11/15/2040, 5.125%	$285,000,000.00	$3,100,600.00	11/16/2010	11/15/2040
(226)	FMB 2013 due 11/15/2043, 4.650%	$250,000,000.00	$1,800,000.00	11/14/2013	11/15/2043
Total (226)		$785,000,000.00	$5,783,100.00		

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Unamortized Debt Expense (181,225,226) (Ref Page: 258) (Part Two)

	Designation of Long-Term	Beginning of Year (f)	Debits (g)	Credits (h)	Balance End of Year (i)
Acct 181					
(181)	Unamortized Debt Expense:	$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)	Jefferson Co. 2001 Series A, due 09/01/2027, Var	$299,089.00	$0.00	$20,393.00	$278,696.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)	Trimble Co. 2000 Series A, due 08/01/2030, Var	$680,605.00	$0.00	$38,707.00	$641,897.00
(181)	Jefferson Co. 2001 Series A, due 09/01/2026, Var	$135,625.00	$0.00	$9,924.00	$125,701.00
(181)	Trimble Co. 2001 Series A, due 09/01/2026, Var	$147,463.00	$0.00	$10,790.00	$136,673.00
(181)	Jefferson Co. 2001 Series B, due 11/01/2027, Var	$163,097.00	$0.00	$10,995.00	$152,101.00
(181)	Trimble Co. 2001 Series B, due 11/01/2027, Var	$163,123.00	$0.00	$10,997.00	$152,126.00
(181)	Trimble Co. 2002 Series A, due 10/01/2032, Var	$735,123.00	$0.00	$37,221.00	$697,902.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)		$0.00	$0.00	$0.00	$0.00
(181)	Trimble Co. 2007 Series A, due 06/01/2033, 4.600%	$970,495.00	$0.00	$47,534.00	$922,961.00
(181)	FMB 2010 due 11/15/2015, 1.625%	$1,497,557.00	$0.00	$522,243.00	$975,314.00
(181)	FMB 2010 due 11/15/2040, 5.125%	$3,323,413.00	$0.00	$119,249.00	$3,204,164.00
(181)	Revolving Credit Facility	$3,440,195.00	$4,162.00	$712,185.00	$2,732,172.00
(181)	Purchase Accounting Adjustment	($3,294,619.00)	$186,562.00	$0.00	($3,108,057.00)
(181)	Louisville Metro 2003A, due 10/01/2033, 1.650%	$1,143,097.00	$46.00	$647,485.00	$495,658.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Unamortized Debt Expense (181,225,226) (Ref Page: 258) (Part Two)

	Designation of Long-Term	Beginning of Year (f)	Debits (g)	Credits (h)	Balance End of Year (i)
(181)	Louisville Metro 2007B, due 06/01/2033, 1.600%	$422,336.00	$0.00	$236,180.00	$186,155.00
(181)	Louisville Metro 2000 Series A, due 05/01/2027, Va		$268,416.00	$111,561.00	$156,855.00
(181)	Louisville Metro 2005A, due 02/01/2035, 2.200%		$290,236.00	$4,209.00	$286,027.00
(181)	Louisville Metro 2007A, due 06/01/2033, 1.150%		$285,620.00	$66,383.00	$219,237.00
(181)	FMB 2013 due 11/15/2043, 4.650% (Case 2012-00233 8		$2,609,393.00	$10,386.00	$2,599,007.00
(181)	S-3 SEC Shelf Registration		$5,104.00	$2,292.00	$2,812.00
Total (181)			$3,649,539.00	$2,618,734.00	$10,857,401.00
Acct 225					
(225)					
Total (225)					
Acct 226					
(226)	Unamortized Debt Discount:	$0.00	$0.00	$0.00	$0.00
(226)	FMB 2010 due 11/15/2015, 1.625%	$507,438.00	$0.00	$176,500.00	$330,938.00
(226)	FMB 2010 due 11/15/2040, 5.125%	$2,881,160.00	$0.00	$103,360.00	$2,777,800.00
(226)	FMB 2013 due 11/15/2043, 4.650%		$1,800,000.00	$7,507.00	$1,792,493.00
Total (226)			$1,800,000.00	$287,367.00	$4,901,231.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Unamortized Loss and Gain on Reqcquired Debt (189,257) (Ref Page: 260)

	Designation of Long-	Date Reacquired (b)	Principle of Debt	Net Gain or Loss (d)	Balance Beginning of	Balance End of Year (f)
Acct 189						
(189)	Gas Reacquired Debt:		$0.00	$0.00	$0.00	$0.00
(189)	1985 Series J, due 07/01/1995	08/01/1990	$25,000,000.00	$787,340.00	$78,715.00	$234,765.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)	1976 Series B,due 09/01/2006	08/01/1993	$35,200,000.00	$439,383.00	$12,810.00	$102,998.00
(189)	1975 Series A, due 09/01/2000	10/01/1992	$31,000,000.00	$286,757.00	$53,525.00	$88,237.00
(189)	1987 Series A, due 08/01/1997	10/01/1992	$60,000,000.00	$2,574,187.00	$480,522.00	$795,969.00
(189)	1990 Series A, due 06/15/2015	06/01/2000	$25,000,000.00	$2,171,404.00	$1,161,255.00	$1,080,231.00
(189)	1990 Series A TC, due 11/01/2020	08/01/2000	$83,335,000.00	$4,298,037.00	$2,526,578.00	$2,382,877.00
(189)	1996 Series A JC, due 09/01/2026	03/01/2002	$22,500,000.00	$1,896,244.00	$1,058,185.00	$980,761.00
(189)	1996 Series A TC, due 09/01/2026	03/01/2002	$27,500,000.00	$1,601,630.00	$893,725.00	$828,325.00
(189)	1997 Series A JC, due 11/01/2027	03/01/2002	$35,000,000.00	$1,256,362.00	$727,523.00	$678,467.00
(189)	1997 Series A TC, due 11/01/2027	03/01/2002	$35,000,000.00	$1,251,639.00	$724,839.00	$675,975.00
(189)	1990 Series B TC, due 10/01/2020	10/01/2002	$41,665,000.00	$1,671,182.00	$1,102,410.00	$1,046,598.00
(189)	1995 Series A JC, due 02/01/2035	11/01/2005	$40,000,000.00	$1,397,647.00	$1,034,476.00	$987,628.00
(189)	1993 Series B JC, due 10/15/2020	11/01/2003	$26,000,000.00	$5,683,169.00	$3,946,981.00	$3,755,998.00
(189)			$0.00	$0.00	$0.00	$0.00
(189)	1992 Series A JC, due 09/01/2017	04/26/2007	$31,000,000.00	$130,784.00	$102,134.00	$97,131.00
(189)	1992 Series A TC, due 09/01/2017	04/26/2007	$60,000,000.00	$172,943.00	$135,057.00	$128,442.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Unamortized Loss and Gain on Reqcquired Debt (189,257) (Ref Page: 260)

	Designation of Long-	Date Reacquired (b)	Principle of Debt	Net Gain or Loss (d)	Balance Beginning of	Balance End of Year (f)
(189)	1993 Series A JC, due 08/15/2013	04/26/2007	$35,200,000.00	$74,067.00	$57,841.00	$55,008.00
(189)	2005 Series A JC, due 02/01/2035	03/24/2008	$40,000,000.00	$1,325,894.00	$1,095,257.00	$796,280.00
(189)	2000 Series A JC, due 05/01/2027	05/01/2008	$25,000,000.00	$692,833.00	$777,976.00	$332,073.00
(189)	2003 Series A JC, due 09/01/2033	07/08/2008	$128,000,000.00	$3,076,081.00	$2,536,718.00	$2,414,064.00
(189)	2007 Series A JC, due 06/01/2033	04/04/2008	$31,000,000.00	$915,910.00	$957,370.00	$501,275.00
(189)	2007 Series B JC, due 06/01/2033	04/04/2008	$35,200,000.00	$620,418.00	$504,151.00	$479,547.00
Total (189)			$872,600,000.00	$32,323,911.00	$19,968,048.00	$18,442,649.00
Acct 257						
(257)						
Total (257)						

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes (Ref Page: 261)

	Details (a)	Amount (b)
Net Income for the Year		$163,405,117.00
Reconciling Items for the Year		
Taxable Income Not Reported on Books		
	Contributions in Aid of Construction	$5,159,429.00
	Interest Rate Swaps	$42,854,000.00
	Purchase Gas Adjustment	$1,100,764.00
	Fuel Adjustment Clause KY	$4,376,000.00
Deductions Recorded on Books Not Deducted For Return		
	Federal Income Taxes - Utility Operating Income	$53,107,974.00
	Federal Income Taxes - Other Income and Deductions	($1,255,593.00)
	Provision for Deferred Income Taxes	$28,249,076.00
	Pensions	$8,403,122.00
	Capitalized Interest	$15,276,411.00
	Loss on Reacquired Debt, Net of Amortization	$1,525,396.00
	Gas Line Tracker	$5,797,265.00
	Storm Damages	$8,348,297.00
	Prepaid Insurance	$1,824,986.00
	Current State Income Taxes	$3,794,160.00
	Nondeductible Expenses	$936,400.00
	Bad Debts Reserves	$610,823.00
	Regulatory Expenses	$649,626.00
	Deferred Operating	$647,695.00
	Other	$971,333.00
Income Recorded on Books Not Included in Return		
	Amortization of Investment Tax Credit	$2,100,342.00
	Environmental Cost Recovery	$1,529,176.00
Deductions on Return Not Charged Against Book Income		
	Tax over Book Depreciation, Net and Repairs	$126,858,110.00
	Cost of Removal	$19,472,540.00
	Demand Side Management	$2,673,248.00
	Regulatory Liability on AROs	$2,432,833.00
	IRC 199 Manufacturing Deduction	$7,324,368.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes (Ref Page: 261)

	Details (a)	Amount (b)
	Contribution Carryforward	$1,820,473.00
	Contingency Reserve	$887,595.00
	Vacation Pay	$432,369.00
	Workers' Compensation	$792,975.00
	Post Retirment Benefits	$674,798.00
	ASC 740-10 State Current Taxes	$584,609.00
	Other	$175,154.00
	Purchase Accounting Adjustments-FMV Bonds	$7,699,695.00
Federal Tax Net Income		$170,323,996.00
Show Computation of Tax		
	Federal tax Net Income	$170,323,996.00
	35% Rounded	$59,613,399.00
	Add: Adjustment of Prior Years' Taxes and Other	($7,761,018.00)
	Total:	$51,852,381.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Taxes Accrued, Prepaid and Charged During Year (Ref Page: 262)

	Kind of Instruction (a)	Bal Beg Yr Taxes Accr (b)	Bal Beg Yr Prepaid Taxes (c)	Taxes Chrg (d)
	Federal:	$0.00	$0.00	$0.00
	Income	$0.00	$0.00	$46,900,895.00
	FICA	$640,795.00	$0.00	$7,002,681.00
		$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00
	Kentucky and Other States:	$0.00	$0.00	$0.00
	Income	$0.00	$0.00	$13,295,648.00
	Public Service Commission	$0.00	$1,116,345.00	$2,274,456.00
	Use (Kentucky)	($289,777.00)	$0.00	$5,999,416.00
	Use (Indiana)	$0.00	$0.00	$101,053.00
	Vehicle License	$0.00	$0.00	$0.00
	Federal & Kentucky:	$0.00	$0.00	$0.00
	Unemployment Insurance	$126,184.00	$0.00	$228,936.00
		$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00
	Local:	$0.00	$0.00	$0.00
	Occupational	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00
	Kentucky & Indiana:	$0.00	$0.00	$0.00
	Property Taxes	$1,258,293.00	$0.00	$21,412,048.00
Total		$1,735,495.00	$1,116,345.00	$97,215,133.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Taxes Accrued, Prepaid and Charged During Year (Ref Page: 262) (Part Two)

	Kind of Instruction (a)	Taxes Paid (e)	Adj (f)	Bal Accr - 236 (g)	Bal Prepaid - 165 (h)
	Federal:	$0.00	$0.00	$0.00	$0.00
	Income	$38,692,155.00	$0.00	$8,208,740.00	$0.00
	FICA	$6,917,126.00	$0.00	$726,350.00	$0.00
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Kentucky and Other States:	$0.00	$0.00	$0.00	$0.00
	Income	$12,515,455.00	$0.00	$780,193.00	$0.00
	Public Service Commission	$2,316,221.00	$0.00	$0.00	$1,158,110.00
	Use (Kentucky)	$4,540,762.00	$0.00	$1,168,877.00	$0.00
	Use (Indiana)	$101,053.00	$0.00	$0.00	$0.00
	Vehicle License	$0.00	$0.00	$0.00	$0.00
	Federal & Kentucky:	$0.00	$0.00	$0.00	$0.00
	Unemployment Insurance	$186,886.00	$0.00	$168,234.00	$0.00
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Local:	$0.00	$0.00	$0.00	$0.00
	Occupational	$0.00	$0.00	$0.00	$0.00
		$0.00	$0.00	$0.00	$0.00
	Kentucky & Indiana:	$0.00	$0.00	$0.00	$0.00
	Property Taxes	$22,248,069.00	$0.00	$422,272.00	$0.00
Total		$87,517,727.00	$0.00	$11,474,666.00	$1,158,110.00

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Taxes Accr, Prepd and Charged - Distribution of Taxes (Ref Page: 262)

	Kind of Instruction (a)	Electric (408.1, 409.1) (i)	Gas (408.1, 409.1) (j)	Other (408.1,409.1) (k)	Other Inc and Ded (l)
	Federal:	$0.00	$0.00	$0.00	$0.00
	Income	$41,181,745.00	$11,926,229.00	$0.00	($1,255,593.00)
	FICA	$6,874,749.00	$1,598,642.00	$0.00	$0.00
	Kentucky & Other States:	$0.00	$0.00	$0.00	$0.00
	Income	$13,122,319.00	$2,955,930.00	$0.00	($192,086.00)
	Public Service Commission	$1,790,451.00	$484,005.00	$0.00	$0.00
	Use (Kentucky)	$0.00	$0.00	$0.00	$0.00
	Use (Indiana)	$0.00	$0.00	$0.00	$0.00
	Vehicle License	$0.00	$0.00	$0.00	$0.00
	Federal & Kentucky:	$0.00	$0.00	$0.00	$0.00
	Unemployment Insurance	$292,030.00	$66,862.00	$0.00	$0.00
	Local:	$0.00	$0.00	$0.00	$0.00
	Occupational	$34,543.00	$8,635.00	$0.00	$0.00
	Kentucky & Indiana:	$0.00	$0.00	$0.00	$0.00
	Property Taxes	$16,040,130.00	$5,327,001.00	$0.00	$5,960.00
Total		$79,335,967.00	$22,367,304.00	$0.00	($1,441,719.00)

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Taxes Accr, Prepd and Charged - Distribution of Taxes (Ref Page: 262) (Part Two)

	Kind of Instruction (a)	Ext Items (409.3) (m)	Other Opn Income (n)	Adj to Ret. Earnings (439)	Other (p)
	Federal:	$0.00	$0.00	$0.00	$0.00
	Income	$0.00	$0.00	$0.00	($4,951,486.00)
	FICA	$0.00	$0.00	$0.00	($1,470,710.00)
	Kentucky & Other States:	$0.00	$0.00	$0.00	$0.00
	Income	$0.00	$0.00	$0.00	($2,590,515.00)
	Public Service Commission	$0.00	$0.00	$0.00	$0.00
	Use (Kentucky)	$0.00	$0.00	$0.00	$5,999,416.00
	Use (Indiana)	$0.00	$0.00	$0.00	$101,053.00
	Vehicle License	$0.00	$0.00	$0.00	$0.00
	Federal & Kentucky:	$0.00	$0.00	$0.00	$0.00
	Unemployment Insurance	$0.00	$0.00	$0.00	($129,956.00)
	Local:	$0.00	$0.00	$0.00	$0.00
	Occupational	$0.00	$0.00	$0.00	($43,178.00)
	Kentucky & Indiana:	$0.00	$0.00	$0.00	$0.00
	Property Taxes	$0.00	$0.00	$0.00	$38,957.00
Total		$0.00	$0.00	$0.00	($3,046,419.00)

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Miscellaneous Current and Accrued Liabilities (242) (Ref Page: 268)

	Item (a)	Balance End Yr (b)
	Vested Vacation Pay Accrued	$5,847,184.00
	No-Notice Gas Payable	$5,664,223.00
	Customer Overpayments	$3,982,591.00
	IBNP Medical and Dental Reserve	$1,389,114.00
	Retirement Income Liability	$702,064.00
	Home Energy Assistance	$750,824.00
	Unearned Revenue - Current	$404,274.00
	Other	$172,127.00
TOTAL		$18,912,401.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Other Deferred Credits (253) (Ref Page: 269)

Description (a)	Balance Beg Yr (b)	Debits Acct (c)	Debit Amt (d)	Credits (e)	Balance End Yr (f)
Contract Retention	$1,973,934.00	0	$0.00	$10,507,280.00	$12,481,214.00
Brown CT Long-Term Service Agreement	$3,317,573.00	107/232	$826,224.00	$0.00	$2,491,349.00
Corporate Headquarters Lease (Jul-12 to Dec-25)	$346,322.00	0	$0.00	$647,695.00	$994,017.00
Valuation of Coal Contracts (Nov-10 to Dec-15)	$1,671,497.00	182.3	$925,578.00	$0.00	$745,919.00
Deferred Compensation	$562,493.00	0	$0.00	$46,738.00	$609,231.00
Prepaid Transmission System Fee: MCI Telecom	$558,076.00	454	$36,796.00	$0.00	$521,280.00
Clearing Accounts Transferred	$20,545.00	184	$5,051,175.00	$5,051,175.00	$20,545.00
Uncertain Tax Position - State	$584,609.00	236	$584,609.00	$0.00	$0.00
Unearned Revenue Pole Attachments	$45,764.00	454	$45,764.00	$0.00	$0.00
TOTAL	$9,080,813.00		$7,470,146.00	$16,252,888.00	$17,863,555.00

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Accumulated Deferred Income Taxes - Other Property (282) (Ref Page: 274)

Acct (a)	Balance Beg Yr (b)	Amt Acct 410.1 (c)	Amt Acct 411.1 (d)	Amt Acct 410.2 (e)	Amt Acct 411.2 (f)
Account 282					
Electric	$419,898,751.00	$110,025,178.00	$61,101,760.00	$0.00	$0.00
Gas	$115,971,222.00	$30,264,713.00	$16,815,221.00	$0.00	$0.00
Other (Define)					
Total	$535,869,973.00	$140,289,891.00	$77,916,981.00	$0.00	$0.00
Other (specify)					
TOTAL Acct 282	$535,869,973.00	$140,289,891.00	$77,916,981.00	$0.00	$0.00
Classification of Total					
Federal Income Tax	$468,153,837.00	$124,635,892.00	$66,759,102.00	$0.00	$0.00
State Income Tax	$67,716,136.00	$15,653,999.00	$11,157,879.00	$0.00	$0.00
Local Income tax					

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Accumulated Deferred Income Taxes - Other Property (282) (Ref Page: 274) (Part Two)

Acct (a)	Debit Adj Acct (g)	Debit Adj Amt (h)	Credit Adj. Acct (i)	Credit Adj. Amt (j)	Balance End Yr
Account 282					
Electric	254	$400,702.00	254	$1,135,049.00	$469,556,516.00
Gas	254	$334,935.00	254	$253,072.00	$129,338,851.00
Other (Define)					
Total		$735,637.00		$1,388,121.00	$598,895,367.00
Other (specify)					
TOTAL Acct 282		$735,637.00		$1,388,121.00	$598,895,367.00
Classification of Total					
Federal Income Tax		$585,374.00		$814,113.00	$526,259,366.00
State Income Tax		$150,263.00		$574,008.00	$72,636,001.00
Local Income tax					

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Accumulated Deferred Income Taxes - Other (283) (Ref Page: 276)

	Acct (a)	Balance Beg Yr (b)	Amt Acct 410.1 (c)	Amt Acct 411.1 (d)	Amt Acct 410.2 (e)	Amt Acct 411.2 (f)
Account 283						
Electric		$155,112,033.00	$16,864,245.00	$52,804,185.00	$0.00	$0.00
Gas		$20,578,495.00	$3,238,170.00	$11,887,244.00	$0.00	$0.00
Other						
Total		$175,690,528.00	$20,102,415.00	$64,691,429.00	$0.00	$0.00
Other (Specify)						
	ASC 740-10 State Tax Current	($204,610.00)	$0.00	$0.00	$204,613.00	$3.00
TOTAL (Acct 283)		$175,485,918.00	$20,102,415.00	$64,691,429.00	$204,613.00	$3.00
Classification of Total						
Federal Income Tax		$148,387,122.00	$17,639,030.00	$55,350,564.00	$204,613.00	$3.00
State Income Tax		$27,098,796.00	$2,463,385.00	$9,340,865.00	$0.00	$0.00
Local Income tax						

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Accumulated Deferred Income Taxes - Other (283) (Ref Page: 276) (Part Two)

	Acct (a)	Debit Adj Acct (g)	Debit Adj Amt (h)	Credit Adj. Acct (i)	Credit Adj. Amt (j)	Balance End Yr
Account 283						
Electric		182/190	$1,141,898.00	182/190	$19,892,584.00	$137,922,779.00
Gas		190	$246,139.00	190	$4,805,568.00	$16,488,850.00
Other						
Total			$1,388,037.00		$24,698,152.00	$154,411,629.00
Other (Specify)						
	ASC 740-10 State Tax Current		$0.00		$0.00	$0.00
TOTAL (Acct 283)			$1,388,037.00		$24,698,152.00	$154,411,629.00
Classification of Total						
Federal Income Tax			$1,369,986.00		$21,084,713.00	$130,594,925.00
State Income Tax			$18,051.00		$3,613,439.00	$23,816,704.00
Local Income tax						

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Other Regualatory Liabilities (Acct 254) (Ref Page: 278)

	Description and Purpose	Bal Beg Yr (b)	Debit Acct Credited (c)	Debits Amount (d)	Credits (e)	Balance End Yr (f)
	ASC 740 - Income Taxes	$42,151,008.00	190/282	$3,550,512.00	$880,787.00	$39,481,283.00
	Gas Supply Clause	$3,094,662.00	803	$4,364,116.00	$4,575,806.00	$3,306,352.00
	Fuel Adjustment Clause	$0.00	440-445	$13,385,000.00	$13,385,000.00	$0.00
	Cost of Removal - Electric	$257,275.00	108	$296,015.00	$38,740.00	$0.00
	Cost of Removal - Gas	$2,175,558.00	108	$2,196,578.00	$21,020.00	$0.00
	0	$0.00	0	$0.00	$0.00	$0.00
	MISO Exit Fee Refund	$892,859.00	143	$305,545.00	$282,955.00	$870,269.00
	Purchased Gas Adjustment	$256,376.00	182.3/803	$259,924.00	$3,548.00	$0.00
	Coal Contracts (Nov-10 to Dec-16)	$61,371,353.00	186	$18,657,374.00	$0.00	$42,713,979.00
	OVEC Power Purchase Contract (Nov-10 to Mar-26)	$74,923,412.00	186	$5,540,496.00	$0.00	$69,382,916.00
	Emission Allowances (Nov-10 to Dec-40)	$1,763,404.00	186	$421,693.00	$200,648.00	$1,542,359.00
	Gas Line Tracker	$255,000.00	480-482	$66,112.00	$5,863,377.00	$6,052,265.00
	LT Interest Rate Swap Non-LKE Affiliate	$7,142,276.00	175	$18,397,081.00	$54,108,804.00	$42,853,999.00
Total		$194,283,183.00		$67,440,446.00	$79,360,685.00	$206,203,422.00

Note:
Due to software space limitations see footnote information provided in total in hard copy Form 1.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Operating Revenues (Ref Page: 301)

	Rev for Transistion Current	Rev for Transistion Prev Yr	GRI and ACA Current Yr (d)	GRI and ACA Prev Yr (e)	other Current Yr (f)
Sales (480-484)	$315,067,271.00	$244,437,870.00	$0.00	$0.00	$0.00
Intracompany Transfers (485)					
Forfeited Discounts (487)	$1,032,692.00	$2,130,534.00	$0.00	$0.00	$0.00
Miscellaneous Service Revenues (488)	$78,405.00	$79,899.00	$0.00	$0.00	$0.00
Revenues from Transportaion of Gas of Others Through Gathering Facilities (489.1)					
Revenues from Transportaion of Gas of Others Through Transmission Facilities (489.2)	$1,281,073.00	$1,301,352.00	$0.00	$0.00	$0.00
Revenues from Transportaion of Gas of Others Through Distribution Facilities (489.3)	$6,385,671.00	$5,974,393.00	$0.00	$0.00	$0.00
Sales of Prod. Ext. from Natural Gas (490)					
Revenues from Natural Gas Proc. by Others (491)					
Incidental gasoline and Oil Sales (492)					
Rent from Gas Property (493)	$372,332.00	$347,119.00	$0.00	$0.00	$0.00
Interdepartmental Rents (494)					
Other Gas Revenues (495)	$3,830.00	$7,232.00	$0.00	$0.00	$0.00
Subtotal	$324,221,274.00	$254,278,399.00	$0.00	$0.00	$0.00
(Less) Provision for Rate Refunds (496)					
Total	$324,221,274.00	$254,278,399.00	$0.00	$0.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Operating Revenues (Ref Page: 301) (Part Two)

	Rev for Transistion	Other Prev Yr (g)	Total Current Yr (h)	Total Prev Yr (i)	MCF Current Yr (h)	MCF Prev Yr (i)
Sales (480-484)	$315,067,271.00	$0.00	$315,067,271.00	$244,437,870.00	34,260,587	26,990,047
Intracompany Transfers (485)						
Forfeited Discounts (487)	$1,032,692.00	$0.00	$1,032,692.00	$2,130,534.00	0	0
Miscellaneous Service Revenues (488)	$78,405.00	$0.00	$78,405.00	$79,899.00	0	0
Revenues from Transportaion of Gas of Others Through Gathering Facilities (489.1)						
Revenues from Transportaion of Gas of Others Through Transmission Facilities (489.2)	$1,281,073.00	$0.00	$1,281,073.00	$1,301,352.00	319,936	651,463
Revenues from Transportaion of Gas of Others Through Distribution Facilities (489.3)	$6,385,671.00	$0.00	$6,385,671.00	$5,974,393.00	11,988,840	11,524,004
Sales of Prod. Ext. from Natural Gas (490)						
Revenues from Natural Gas Proc. by Others (491)						
Incidental gasoline and Oil Sales (492)						
Rent from Gas Property (493)	$372,332.00	$0.00	$372,332.00	$347,119.00	0	0
Interdepartmental Rents (494)						
Other Gas Revenues (495)	$3,830.00	$0.00	$3,830.00	$7,232.00	0	0
Subtotal	$324,221,274.00	$0.00	$324,221,274.00	$254,278,399.00	46,569,363	39,165,514
(Less) Provision for Rate Refunds (496)						
Total	$324,221,274.00	$0.00	$324,221,274.00	$254,278,399.00	46,569,363	39,165,514

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Rev From Transportation of Gas through Transmission Facilities (489.2) (Ref Page: 304)

Rate Schedule and Zone	Rev for Transition Costs	Rev for Transition Costs	Rev for GRI and ACA	Rev for GRI and ACA	Other Rev Current (f)
RATE FT/PADDY'S RUN	$1,281,073.00	$1,301,352.00	$0.00	$0.00	$0.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Rev From Transportation of Gas through Transmission Facilities (489.2) (Ref Page: 304) (Part Two)

Rate Schedule and Zone	Other Rev Previous (g)	Total Operating Rev	Total Operating Rev	MCF Current (j)	MCF Previous (k)
RATE FT/PADDY'S RUN	$0.00	$1,281,073.00	$1,301,352.00	319,936	651,463

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Other Gas Revenues (495) (Ref Page: 308)

Description of Transaction	Revenues in Dollars
Miscellaneous - All Minor Items	$3,830.00
	$3,830.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Operation and Maintenance - 1. Production (Ref Page: 317)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
1. PRODUCTION EXPENSES		
A. Manufactured Gas Production		
Manufactured Gas Production		
B. Natural Gas Production		
B1. Natural Gas Produciton and Gathering		
Operation		
Operation Supervision and Engineering (750)		
Production Maps and Records (751)		
Gas Well Expenses (752)		
Field Lines Expenses (753)		
Field compressor Station Expenses (754)		
Field Compressor Station Fuel and Power (755)		
Field Measuring and Regulating Station Expenses (756)		
Purification Expenses (757)		
Gas Well Royalties (758)		
Other Expenses (759)		
Rents (760)		
18. Total Operation		$0.00
Maintenance		
Maintenance Supervision and Engineering (761)		
Maintenance of Structures and Improvements (762)		
Maintenance of Producing Gas Wells (763)		
Maintenance of Field Lines (764)		
Maintenance of Field Compressor Station Equipment (765)		
Maintenance of Field Measuring and Regulating Station Equipment (766)		
Maintenance of Purification Equipment (767)		
Maintenance of Drilling and Cleaning Equipment (768)		
Maintenance of Other Equipment (769)		
29. Total Maintenance		$0.00
Total Natural Gas Production and Gathering (Lines 18,29(		$0.00
B2. Products Extraction		

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Operation and Maintenance - 1. Production (Ref Page: 317)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Operation		
Operation Supervision and Engineering (770)		
Operation Labor (771)		
Gas Shrinkage (772)		
Fuel (773)		
Power (774)		
Materials (775)		
Operation Supplies and Expenses (776)		
Gas Processed by Others (777)		
Royalties on Products Extracted (778)		
Marketing Expenses (779)		
Products Purchased for Resale (780)		
Variation in Products Inventory (781)		
(Less) Extracted Products Used by the Utility - Credit (782)		
Rents (783)		
47. Total Operation		$0.00
Maintenance		
Maintenance Supervision and Engineering (784)		
Maintenance of Structures and Improvements (785)		
Maintenance of Extraction and Refining Equipment (786)		
Maintenance of Pipe Lines (787)		
Maintenance of Extracted Products Storage Equipment (788)		
Maintenance of Compressor Equipment (789)		
Maintenance of Gas Measuring and Regulating Equipment (790)		
Maintenance of Other Equipment (791)		
57. Total Maintenance		$0.00
58. Total Products Extraction (Lines 47 and 57)		$0.00
C. Exploration and Development		
Operation		
Delay Rentals (795)		
Nonproductive Well Drilling (796)		
Abandoned Leases (797)		

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Operation and Maintenance - 1. Production (Ref Page: 317)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Other Exporation (798)		
65. Total Exploration and Development		$0.00
D. Other Gas Supply Expenses		
Operation		
Natural Gas Well Head Purchases (800)		
Natural Gas Well Head Purchases, Intracompany Transfers (800.1)		
Natural Gas Field Line Purchases (801)		
Natural Gas Gasoline Plant Outlet Purchases (802)		
Natural Gas Transmission Line Purchases (803)	$165,638,645.00	$104,830,485.00
Natural Gas City Gate Purchases (804)		
Liquified Natural Gas Purchases (804.1)		
Other Gas Purchases (805)		
(Less) Purchases Gas Cost Adjustments (805.1)		
77. Total Purchased Gas	$165,638,645.00	$104,830,485.00
78. Exchange Gas (806)	$330,454.00	$525,097.00
Purchased Gas Expense		
Well Expense - Purchased Gas (807.1)		
Operation of Purchased Gas Measuring Stations (807.2)		
Maintenance of PUrchased Gas Measuring Stations (807.3)		
Purchased Gas Calculations Expenses (807.4)	$34,854.00	$65,618.00
Other Purchased Gas Expenses (807.5)	$689,302.00	$754,708.00
85. Total Purchased Gas Expenses	$724,156.00	$820,326.00
Gas Withdrawn from Storage - Debit (808.1)	$44,967,412.00	$50,343,696.00
(Less) Gas Delivered to Storage (Credit) (808.2)	$52,239,510.00	$40,946,221.00
Withdrawals of Liquefied natural Gas for Processing - Debit (809.1)		
(Less) Delieveries of Natural Gas for Processing- Credit (809.2)		
Gas used in Utility Operation - Credit		
91. Gas Used for Compressor Station Fuel - Credit (810)	($532,094.00)	($570,049.00)
92..Gas Used for Products Extraction - Credit (811)		
93..Gas Used for Other Utility Operations - Credit (812)	($146,577.00)	($111,585.00)

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Operation and Maintenance - 1. Production (Ref Page: 317)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
94. Total Gas Used in Utility Operations - Credit (91-93)	($678,671.00)	($681,634.00)
95. Other Gas Supply Expenses (813)		
97. Total Other Gas Supply Exp (77,78,85,86-89,94,95)	$158,742,486.00	$114,891,749.00
Total Production Expenses (3,30,58,65,96)	$158,742,486.00	$114,891,749.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Operation and Maintenance - 2. Natural Gas Storage (Ref Page: 320)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
A. Underground Storage Expenses		
Operation		
Operation Supervision and Engineering (814)	$480,443.00	$532,113.00
Maps and Records (815)		
Wells Expenses (816)	$418,565.00	$486,737.00
Lines Expenses (817)	$642,361.00	$573,370.00
Compressor Station Expenses (818)	$1,762,219.00	$1,516,084.00
Compressor Station Fuel and Power (819)	$537,379.00	$573,908.00
Measuring and Regulating Station Expenses (820)		
Purification Expenses (821)	$1,320,130.00	$1,351,832.00
Exploration and Development (822)		
Gas Losses (823)	$1,735,363.00	$1,879,976.00
Other Expenses (824)	$9,750.00	$12,993.00
Storage well Royalties (825)	$88,659.00	$56,343.00
Rents (826)	$32,301.00	$35,419.00
114. Total Operation	$7,027,170.00	$7,018,775.00
Maintenance		
Maintenance Supervision and Engineering (830)	$388,977.00	$400,588.00
Maintenance of Structures and Improvements (831)		
Maintenance of Reservoirs and Wells (832)	$825,739.00	$744,493.00
Maintenance of Lines (833)	$155,842.00	$167,530.00
Maintenance of Compressor Station Equipment (834)	$839,617.00	$816,756.00
Maintenance of Measuring and Regulating Station Equipment (835)	$20,840.00	$25,946.00
Maintenance of Purification Equipmetn (836)	$873,839.00	$612,009.00
Maintenance of Other Equipment (837)	$36,132.00	$31,239.00
124. Total Maintenance	$3,140,986.00	$2,798,561.00
Total Underground Storage (Lines 114 and 124)	$10,168,156.00	$9,817,336.00
B. Other Storage Expenses		
Operation		

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Operation and Maintenance - 2. Natural Gas Storage (Ref Page: 320)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Operation Supervision and Engineering (840)		
Operation Labor and Expenses (841)		
Rents (842)		
Fuel (842.1)		
Power (842.2)		
Gas Losses (842.3)		
134. Total Operation		
Maintenance		
Maintenance Supervision and Engineering (843.1)		
Maintenance of Structures and Improvements (843.2)		
Maintenance of Gas Holders (843.3)		
Maintenance of Purification Equipment (843.4)		
Maintenance of Liquefaction Equipment (843.5)		
Maintenance of Vaporizing Equipment (843.6)		
Maintenance of Compressor Equipment (843.7)		
Maintenance of Measuring and Regulating Equipment (843.8)		
Maintenance of Other Equipment (843.9)		
145. TOTAL Maintenance		$0.00
Total Other Storage Expenses (Lines 134 and 145)		$0.00
C. Liquefied Natural Gas Terminaling and Processing Expenses		
Operation		
Operation Supervision and Engineering (844.1)		
LNG Processing Terminal Labor and Expenses (844.2)		
Liquefaction Processing Labor and Expenses (844.3)		
Liquefaction Transportaion Labor and Expenses (844.4)		
Measuring and Regulating Labor and Expenses (844.5)		
Compressor Station Labor and Expenses (544.6)		
Communication System Expenses (844.7)		
System Control and Load Dispatching (844.8)		
Fuel (845.1)		
Power (845.2)		
Rents (845.3)		

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Operation and Maintenance - 2. Natural Gas Storage (Ref Page: 320)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Demurrage Charges (845.4)		
(Less) Wharfage Receipts - Credit (845.5)		
Processing Liquefied or Vaporized Gas by Others (845.6)		
Gas Losses (846.1)		
Other Expenses (846.2)		
Total Operation		$0.00
Maintenance		
Maintenance Supervision and Engineering (847.1)		
Maintenance of Structures and Improvements (847.2)		
Maintenance of LNG Processing Terminal equipment (847.3)		
Maintenance of LNG Transportation Equipment (847.4)		
Maintenance of Measuring and Regulating Equipment (847.5)		
Maintenance of Compressor Station Equipment (847.6)		
Maintenance of Communication Equipment (847.7)		
Maintenance of Other Equipment (847.8)		
175. Total Maintenance		$0.00
176. Total Liquiefied Nat Gas Terminaling and Proc Exp (Lines 165 and 175)		$0.00
177. Total Natural Gas Storage (Lines 125,146 and 176)	$10,168,156.00	$9,817,336.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Operation and Maintenance - 3 through 8 (Ref Page: 323)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
3. TRANSMISSION EXPENSES		
Operation		
Operation Supervision and Engineering (850)	$19,833.00	$38,931.00
System Control and Load Dispatching (851)	$320,655.00	$362,679.00
Communication System Expenses (852)		
Compressor Station labor and Expenses (853)		
Gas for Compressor Station Fuel (854)		
Other Fuel and Power for Compressor Stations (855)		
Mains Expenses (856)	$474,874.00	$394,993.00
Measuring and Regulating Stations Expenses (857)		
Transmission and Compression of Gas by Others (858)		
Other Expenses (859)		
Rents (860)	$6,978.00	$6,239.00
191. Total Operation	$822,340.00	$802,842.00
Maintenance		
Maintenance Supervision and Engineering (861)		
Maintenance of Structures and Improvements (862)		
Maintenance of Mains (863)	$523,964.00	$2,203,165.00
Maintenance of Compressor Station Equipment (864)		
Maintenance of Measuring and Regulating Station Equipment (865)		
Maintenance of Communication Equipment (866)		
Maintenance of Other Equipment (867)		
200. Total Maintenance	$523,964.00	$2,203,165.00
201. Total Transmission Expenses (Total 191 and 200)	$1,346,304.00	$3,006,007.00
4. DISTRIBUTION EXPENSES		
Operation		
Operation Supervision and Engineering (870)		
Distribution Load Dispatching (871)	$464,858.00	$480,935.00
Compressor Station Labor and Expenses (872)		
Compressor Station Fuel and Power (873)		
Mains and Services Expenses (874)	$2,807,975.00	$2,754,797.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Operation and Maintenance - 3 through 8 (Ref Page: 323)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
Measuring and Regulating station Expenses - General (875)	$1,077,454.00	$695,331.00
Measuring and Regulating Station Expenses - Industrial (876)	$264,091.00	$275,703.00
Measuring and Regulating Station Expenses - City Gas Check Station (877)	$180,087.00	$136,181.00
Meter and House Regulator Expenses (878)	$695,453.00	$460,324.00
Customer Installations Expenses (879)	$150,608.00	$625,310.00
Other Expenses (880)	$3,320,134.00	$2,934,914.00
Rents (881)	$10,098.00	$10,676.00
216. Total Operation	$8,970,758.00	$8,374,171.00
Maintenance		
Maintenance Supervision and Engineering (885)		
Maintenance of Structures and Improvements (886)	$600,207.00	$570,959.00
Maintenance of Mains (887)	$9,218,684.00	$9,920,215.00
Maintenance of Compressor Station Equipment (888)		
Maintenance of Measuring and Regulating Station Equipment - General (889)	$63,592.00	$100,398.00
Maintenance of Measuring and Regulating Station Equipment - Industrial (890)	$217,909.00	$209,332.00
Maintenance of Measuring and Regulating Station Equipment - City Gate Check Station (891)	$603,338.00	$353,448.00
Maintenance of Services (892)	$1,757,450.00	$1,036,737.00
Maintenance of Meters and House Regulators (893)		
Maintenance of Other Equipment (894)	$138,958.00	$230,125.00
228. Total Maintenance	$12,600,138.00	$12,421,214.00
229. Total Distribution Expenses (Lines 216 and 228)	$21,570,896.00	$20,795,385.00
5. CUSTOMER ACCOUNTS EXPENSES		
Operation		
Supervision (901)	$884,855.00	$783,847.00
Meter Reading Expenses (902)	$1,853,163.00	$1,784,930.00
Customer Records and Collections Expenses (903)	$4,399,785.00	$4,562,429.00
Uncollectible Accounts (904)	$334,880.00	$402,205.00
Miscellaneous Customer Accounst Expenses (905)	$98,594.00	$258,081.00
237. Total Customer Accounts Expenses	$7,571,277.00	$7,791,492.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Operation and Maintenance - 3 through 8 (Ref Page: 323)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
Operation		
Supervision (907)	$51,444.00	$59,946.00
Customer Assistance Expenses (908)	$2,794,176.00	$3,415,895.00
Informational and Instructional Expenses (909)	$83,884.00	$58,468.00
Miscellaneous Customer Service and Informational Expenses (910)	$86,424.00	$134,495.00
244. Total Customer Service and Informational Expenses	$3,015,928.00	$3,668,804.00
7. SALES EXPENSES		
Operation		
Supervision (911)		
Demonstrating and Selling Expenses (912)		
Advertising Expenses (913)		$437.00
Miscellaneous Sales Expenses (916)		
251. TOTAL Sales Expenses		$437.00
8. ADMINISTRATIVE AND GENERAL EXPENSES		
Operation		
Administrative and General Salaries (920)	$4,946,727.00	$4,111,289.00
Office Supplies and Expenses (921)	$1,234,693.00	$1,339,048.00
(Less) Administrative Expenses Transferred - Credit (922)	$519,967.00	$440,937.00
Outside Services Employed (923)	$2,715,245.00	$1,023,027.00
Property Insurance (924)	$103,013.00	$106,450.00
Injuries and Damanges (925)	$1,182,777.00	$486,558.00
Employee Pensions and benefits (926)	$8,639,281.00	$8,323,983.00
Franchise Requirements (927)	$589,226.00	$578,189.00
Regulatory Commission Expenses (928)	$198,293.00	$173,974.00
(Less) Duplicate Charges - Credit (929)	$549,513.00	$544,321.00
General Advertising Expenses (930.1)	$230,846.00	$165,443.00
Miscellaneous General Expenses (930.2)	$369,526.00	$396,830.00
Rents (931)	$498,298.00	$422,806.00
267. Total Operation	$19,638,445.00	$16,142,339.00
Maintenance		

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Operation and Maintenance - 3 through 8 (Ref Page: 323)

	Amt for Current Yr (b)	Amt for Prev Yr (c)
269. Maintenance of General Plant (935)	$1,502,448.00	$3,745,709.00
270. Total Administrative and General (Total 267 and 269)	$21,140,893.00	$19,888,048.00
Total Gas O and M Expenses (Total Lines 97,177,201,229,237,244,251 and 270)	$223,555,940.00	$179,859,258.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Used in Utility Operations (Ref Page: 331)

	Purpose (a)	Acct Charged (b)	Natural Gas Used MCF (c)	Natural Gas Amount of Credit (d)	Manufactured Gas MCF (e)	Manufactured Gas Amount of Credit (f)
Gas Used for Compressor Station Fuel - Credit (810)		819	135,604	$532,094.00	0	$0.00
Gas Used For Products Extration - Credit (811)						
Gas Shrinkage and Other Usage in Respondent`s Own Processing						
Gas Shrinkage, etc. for Respondent`s Gas Processed by Others						
Gas Used for Other Utility Operations - Credit (812)						
(Report seperately each principal use. Group minor uses.)						
	City Gate Station	877	19,842	$80,867.00	0	$0.00
	Gas Used in Electric Generation	547	5,334	$22,691.00	0	$0.00
	Various	Various	11,062	$43,019.00	0	$0.00
Total			171,842	$678,671.00	0	$0.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Other Gas Supply Expenses (813) (Ref Page: 334)

Description (a)	Amount (b)
No activity	$0.00
Total	$0.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Miscellaneous General Expenses (Acct 930.2) (Ref Page: 335)

	Description	Amount
Industry association dues		$14,500.00
Experimental and general research expenses.		
a. Gas Research Institute (GRI)		
b. Other		
Publishing and distributing information and reports to stockholders, trustee, registrar and transfer agent fees and expenses and other expenses		
Other		
	Swap Termination Amortization	$81,580.00
	American Gas Association Amortization	$163,320.00
	Miscellaneous	$110,126.00
Total		$369,526.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Depreciation, Depletion and Amortization of Gas Plant (403,403.1,404.1,404.2,404.3,405) (Ref Page: 336)

	Depreciation 403 (b)	Depreciation Exp	404.1 (d)	404.2 (e)	404.3 (f)	405 (g)	Total (h)
Intangible Plant	$0.00	$0.00	$0.00	$0.00	$41.00	$0.00	$0.00
Production Plant, manufactured gas							
Production and gathering plant, natural gas							
Products extraction plant							
Underground gas storage plant	$1,745,002.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,745,002.00
Other storage plant							
Base load LNG terminaling and processing plant							
Transmission plant	$214,160.00	$0.00	$0.00	$0.00	$0.00	$0.00	$214,160.00
Distribution plant	$18,371,489.00	$0.00	$0.00	$0.00	$0.00	$0.00	$18,371,489.00
General Plant	$277,654.00	$0.00	$0.00	$0.00	$0.00	$0.00	$277,654.00
Common plant - gas	$3,140,388.00	$0.00	$0.00	$0.00	$2,305,112.00	$0.00	$5,445,541.00
Other							
Total	$23,748,693.00	$0.00	$0.00	$0.00	$2,305,153.00	$0.00	$26,053,846.00

Note:
In August 2013, year-to-date regulatory offsets for depreciation on asset retirement cost assets and ARO liability accretion were reclassed from Regulatory Credits (407.4) to Depreciation Expense on Asset Retirement Costs (403.1) and Accretion Expense (411.10).

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Depreciation, Depletion and Amortization of Gas Plant (cont) (Ref Page: 338)

	Functional Classification (a)	Plant Bases (thousands) (b)	Applied Depr or Amort Rates (c)
Production and Gathering Plant			
Offshore			
Onshore			
	Underground Storage Plant	96,550	2
Underground Gas Storage Plant			
Transmission Plant			
Offshore			
Onshore			
	Transmission Plant	35,751	1
General Plant			
	General Plant	5,990	3
	Distribution Plant	700,781	3

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Particulars Concerning Cetrain Income Deductions and Interest Charges Accounts (Ref Page: 340)

Item (a)	Amount (b)
Account 426.1-Donations	$0.00
Association of Community Ministries	$412,500.00
Various	$2,206,302.00
Total Account 426.1	$2,618,802.00
Account 426.3-Penalties	$297,610.00
Total Account 426.3	$297,610.00
Account 426.4-Civic, Political & Related Activity	$986,880.00
Total Account 426.4	$986,880.00
Account 426.5-Other Deductions	$1,404,757.00
Total Account 426.5	$1,404,757.00
Account 430-Interest on Debt to Associated Company	$0.00
LG&E and KU Energy LLC	$0.00
Kentucky Utilities Company	$10,061.00
Other	$0.00
Total Account 430	$10,061.00
Account 431-Other Interest Expense	$0.00
Financial Liabilities	$1,177,269.00
Interest on Commercial Paper Short Term Debt	$221,086.00
Interest on Tax Deficiencies	$57,500.00
Customer Deposits - 6% Interest Rate	$45,603.00
Interest on Rates Refund	$18,419.00
DSM Cost Recovery	$609.00
Other	$0.00
Total Account 431	$1,520,486.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Regulatory Commission Expenses (928) (Ref Page: 350)

Description (a)	Assessed by Reg Commission (b)	Expenses of the Utility (c)	Total Expenses (d)	Deferred in 182.3 Beg of Yr (e)	Expenses Incurred Charged to Department
Federal Energy Regulatory Commission	$0.00	$0.00	$0.00	$0.00	
Annual Charge	$350,681.00	$0.00	$350,681.00	$0.00	Electric
Administrative Charge, Project #289	$173,558.00	$0.00	$173,558.00	$0.00	Electric
2009 Rate Case - Electric (Aug-10 to Jul-13)	$0.00	$163,236.00	$163,236.00	$163,236.00	Electric
2009 Rate Case - Gas (Aug-10 to Jul-13)	$0.00	$93,416.00	$93,416.00	$93,416.00	Gas
2012 Rate Case - Electric (Jan-13 to Dec-15)	$0.00	$298,138.00	$298,138.00	$894,413.00	Electric
2012 Rate Case - Gas (Jan-13 to Dec-15)	$0.00	$94,935.00	$94,935.00	$284,806.00	Gas
2011 Gen Mgmt Audit - Electric (Jan-13 to Dec-15)	$0.00	$30,528.00	$30,528.00	$91,583.00	Electric
2011 Gen Mgmt Audit - Gas (Jan-13 to Dec-15)	$0.00	$9,943.00	$9,943.00	$29,825.00	Gas
	$524,239.00	$690,196.00	$1,214,435.00	$1,557,279.00	

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Regulatory Commission Expenses (928) (Ref Page: 350) (Part Two)

Description (a)	Expenses Incurred Charged to Acct (g)	Expenses Incurred Charged to Amount	Expenses Incurred Deferred to 182.3 (i)	Amortized Contra Acct (j)	Amortized Amt (k)	Deferred in 182.3 End of Yr (l)
Federal Energy Regulatory Commission		$0.00	$0.00		$0.00	$0.00
Annual Charge	928	$350,681.00	$0.00		$0.00	$0.00
Administrative Charge, Project #289	928	$173,558.00	$0.00		$0.00	$0.00
2009 Rate Case - Electric (Aug-10 to Jul-13)	928	$163,236.00	$0.00	928	$163,236.00	$0.00
2009 Rate Case - Gas (Aug-10 to Jul-13)	928	$93,416.00	$0.00	928	$93,416.00	$0.00
2012 Rate Case - Electric (Jan-13 to Dec-15)	928	$298,138.00	$76.00	928	$298,138.00	$596,351.00
2012 Rate Case - Gas (Jan-13 to Dec-15)	928	$94,935.00	$24.00	928	$94,935.00	$189,895.00
2011 Gen Mgmt Audit - Electric (Jan-13 to Dec-15)	928	$30,528.00	$0.00	928	$30,528.00	$61,055.00
2011 Gen Mgmt Audit - Gas (Jan-13 to Dec-15)	928	$9,943.00	$0.00	928	$9,943.00	$19,882.00
		$1,214,435.00	$100.00		$690,196.00	$867,183.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Distribution of Salaries and Wages - Electric (Ref Page: 355)

Specify	Direct Payroll (b)	Alloc Clearing Accts (c)	Total (d)
Electric			
Operation			
3. Production	$23,264,337.00	$5,786,593.00	$29,050,930.00
4. Transmission	$2,922,592.00	$863,216.00	$3,785,808.00
5. Distribution	$7,806,010.00	$1,995,237.00	$9,801,247.00
6. Customer Accounts	$3,731,716.00	$1,119,581.00	$4,851,297.00
7. Customer Service and Informational	$789,073.00	$243,267.00	$1,032,340.00
8. Sales	$0.00	$0.00	$0.00
9. Administrative and General	$15,519,000.00	$3,855,940.00	$19,374,940.00
10. Total Operation	$54,032,728.00	$13,863,834.00	$67,896,562.00
Maintenance			
12. Production	$11,012,179.00	$2,656,776.00	$13,668,955.00
13. Transmission	$357,430.00	$98,676.00	$456,106.00
14. Distribution	$2,748,571.00	$526,198.00	$3,274,769.00
15. Administrative and General	$2,222,824.00	$618,831.00	$2,841,655.00
16. Total Maint	$16,341,004.00	$3,900,481.00	$20,241,485.00
Total Operation and Maintenance			
18. Total Production (Lines 3 and 12)	$34,276,516.00	$8,443,369.00	$42,719,885.00
19. Total Transmission (Lines 4 and 13)	$3,280,022.00	$961,892.00	$4,241,914.00
20. Total Distribution (Lines 5 and 14)	$10,554,581.00	$2,521,435.00	$13,076,016.00
21. Customer Accounts (Transcribe from Line 6)	$3,731,716.00	$1,119,581.00	$4,851,297.00
22. Customer Service and Informational (Transcribe from Line 7)	$789,073.00	$243,267.00	$1,032,340.00
23. Sales (Transcribe from Line 8)	$0.00	$0.00	$0.00
24. Administrative and Generatl (Lines 9 and 15)	$17,741,824.00	$4,474,771.00	$22,216,595.00
25. Total Oper. and Maint. (Lines 18-24)	$70,373,732.00	$17,764,315.00	$88,138,047.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Distribution of Salaries and Wages - Gas (Ref Page: 355)

Specify	Direct Payroll (b)	Alloc Clearing Accts (c)	Total (d)
Gas			
Operation			
28. Production -- Manufactured Gas	$0.00	$0.00	$0.00
29. Production -- Nat. Gas (Including Expl and Dev.)	$0.00	$0.00	$0.00
20. Other Gas Supply	$528,021.00	$142,949.00	$670,970.00
31. Storage, LNG Terminaling and Processing	$1,705,065.00	$423,880.00	$2,128,945.00
32. Transmission	$490,754.00	$127,879.00	$618,633.00
33. Distribution	$2,972,172.00	$748,908.00	$3,721,080.00
34. Customer Accounts	$3,053,012.00	$916,000.00	$3,969,012.00
35. Customer Service and Informational	$266,102.00	$80,160.00	$346,262.00
36. Sales	$0.00	$0.00	$0.00
37. Administrative and General	$3,780,247.00	$794,511.00	$4,574,758.00
38. Total Operation	$12,795,373.00	$3,234,287.00	$16,029,660.00
Maintenance			
40. Production -- Manufactured Gas	$0.00	$0.00	$0.00
41. Production -- Natural Gas	$0.00	$0.00	$0.00
42. Other Gas Supply	$0.00	$0.00	$0.00
43. Storage, LNG Terminaling and Processing	$1,337,658.00	$345,061.00	$1,682,719.00
44. Transmission	$69,093.00	$1,444.00	$70,537.00
45. Distribution	$5,130,603.00	$1,204,605.00	$6,335,208.00
46. Administrative and General	$907,667.00	$252,740.00	$1,160,407.00
47. Total Maint	$7,445,021.00	$1,803,850.00	$9,248,871.00
Total Operation and Maintenance			
50. Total Production -- Manufactured Gas (Lines 28 and 40)	$0.00	$0.00	$0.00
51. Total Production -- Natural Gas (Lines 29 and 41)	$0.00	$0.00	$0.00
52. Total Other Gas Supply (Lines 30 and 42)	$528,021.00	$142,949.00	$670,970.00
53. Total Storage LNG Terminaling and Processing (Lines 31 and 43)	$3,042,723.00	$768,941.00	$3,811,664.00

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Distribution of Salaries and Wages - Gas (Ref Page: 355)

	Specify	Direct Payroll (b)	Alloc Clearing Accts (c)	Total (d)
54. Total Transmission (Lines 32 and 44)		$559,847.00	$129,323.00	$689,170.00
55. Total Distribution (Lines 33 and 45)		$8,102,775.00	$1,953,513.00	$10,056,288.00
56. Customer Accounts (Transcribe Line 34)		$3,053,012.00	$916,000.00	$3,969,012.00
57. Customer Service and Informational (Transcribe Line 35)		$266,102.00	$80,160.00	$346,262.00
58. Sales (Transcribe Line 36)		$0.00	$0.00	$0.00
59. Administrative and General (Line 37 + 46)		$4,687,914.00	$1,047,251.00	$5,735,165.00
60. Total Operation and Maint (Lines 50-59)		$20,240,394.00	$5,038,137.00	$25,278,531.00
Other Utility Departments				
62. Operation and Maintenance		$0.00	$0.00	$0.00
63. Total All Utility Dept (Lines 25,60,62)		$90,614,126.00	$22,802,452.00	$113,416,578.00

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Distribution of Salaries and Wages - Utility Plant (Ref Page: 356)

	Specify	Direct Payroll (b)	Alloc Clearing Accts (c)	Total (d)
Utility Plant				
Construction (By Utility Departments)				
66. Electric Plant		$9,938,504.00	$8,319,112.00	$18,257,616.00
67. Gas Plant		$5,098,826.00	$4,563,389.00	$9,662,215.00
68. Other	Common Utility Plant	$2,289,051.00	$1,086,356.00	$3,375,407.00
69. Total Construction		$17,326,381.00	$13,968,857.00	$31,295,238.00
70. Plant Removal (By Utility Departments)				
71. Electric Plant		$1,035,830.00	$567,851.00	$1,603,681.00
72. Gas Plant		$157,332.00	$131,239.00	$288,571.00
73. Other	Common Utility Plant	$198.00	$56.00	$254.00
74. Total Plant Removal		$1,193,360.00	$699,146.00	$1,892,506.00
75. Other Accounts				
	Accounts Receivable (work done for others)	$7,017,252.00	$1,652,001.00	$8,669,253.00
	Miscellaneous Deferred Debits & Preliminary Survey	$77,369.00	($183,537.00)	($106,168.00)
	Civic, Political & Related Activities & Other	$446,340.00	$133,250.00	$579,590.00
	Nonjurisdictional	$1,726,419.00	$431,196.00	$2,157,615.00
76. Total Other Accounts		$9,267,380.00	$2,032,910.00	$11,300,290.00
77. Total Salaries and Wages		$118,401,247.00	$39,503,365.00	$157,904,612.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Charges for Outside Professional and Other Consultative Services (Ref Page: 358)

Description (a)	* (b)	Amount (2)
ACCU READ SERVICES		$3,403,844.00
ASSURED ASSET PROTECTION INC		$479,352.00
BAKER HUGHES BUSINESS		$316,251.00
BELLOMY RESEARCH INC		$397,652.00
CGI TECHNOLOGIES AND SOLUTIONS INC		$624,618.00
CREATIVE ALLIANCE		$984,649.00
DELOITTE CONSULTING LLP		$1,469,944.00
ENERGY ECONOMICS INC		$1,203,852.00
ENERGY MANAGEMENT AND SERVICES CO		$598,654.00
EVANS CONSTRUCTION CO INC		$1,427,002.00
FISHEL CO		$613,601.00
FLAGPROS LLC		$290,187.00
FROST BROWN TODD LLC		$375,971.00
FURMANITE AMERICA INC		$250,201.00
GNC CONSULTING INC		$356,776.00
HALL CONTRACTING OF KENTUCKY INC		$1,754,200.00
HONEYWELL INDUSTRY SOLUTIONS		$806,908.00
HONEYWELL INTERNATIONAL INC		$526,757.00
IVEY MECHANICAL LLC		$296,773.00
J Y LEGNER ASSOCIATES INC		$658,350.00
KENTUCKIANA TRAFFIC AND PATROL SERVICES LLC		$711,331.00
MEC CONSTRUCTION LLC		$4,122,757.00
MILLER PIPELINE CORP		$20,976,939.00
OPOWER INC		$352,342.00
OPS PLUS INC		$535,830.00
ORACLE AMERICA INC		$413,192.00
PREMIER ENERGY SERVICES LLC		$3,041,476.00
ROSEN USA		$610,311.00
SAMAC PAINTING INC		$1,017,460.00
SCHARDEIN MECHANICAL		$518,495.00
SECURITAS SECURITY SERVICES USA INC		$493,909.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Charges for Outside Professional and Other Consultative Services (Ref Page: 358)

Description (a)	* (b)	Amount (2)
SERCO INC		$1,429,821.00
SOUTHERN PIPELINE CONST CO		$5,974,194.00
STOLL CONSTRUCTION AND PAVING CO INC		$2,913,137.00
SURVEYS AND ANALYSIS INC		$1,654,685.00
TEK SYSTEMS		$515,116.00
USIC LOCATING SERVICES INC		$1,644,886.00
XEROX CORP		$908,806.00
OTHER		$14,271,572.00
TOTAL		$78,941,801.00

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Compressor Stations (Ref Page: 508)

Name of Station and	Number of Units (b)	Certified Horsepower (c)	Plant Cost (d)	Fuel or Power (e)	Fuel or Power Type
Magnolia Compressor Station	6	8,010	$13,181,983.00	$444,012.00	Natural Gas
Muldraugh Compressor Station	9	9,545	$26,646,479.00	$88,082.00	Natural Gas
Field Compressor Stations for Self-Use to	0	0	$0.00	$0.00	
Recover Underground Storage Gas:	0	0	$0.00	$0.00	
Doe Run- Brandenburg, KY and Laconia, IN	9	1,000	$1,713,985.33	$151,750.00	Gas/Electricity
Muldraugh-Muldraugh, KY	1	30	$110,905.00	$432.00	Electricity

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Compressor Stations (Ref Page: 508) (Part Two)

Name of Station and	Other (f)	Gas for Comp Fuel MCF	Total Comp Hours	Comp operating at Time	Date of Station Peak (j)
Magnolia Compressor Station	$1,593,077.00	98,963	9,926	5	12/23/2013
Muldraugh Compressor Station	$2,104,484.00	122,671	1,771	4	01/25/2013
Field Compressor Stations for Self-Use to	$0.00	0	0	0	
Recover Underground Storage Gas:	$0.00	0	0	0	
Doe Run- Brandenburg, KY and Laconia, IN	$1,488,302.00	2,760	21,114	0	
Muldraugh-Muldraugh, KY	$0.00	0	3,132	0	

Note:
Doe Run - Brandenburg, KY and Laconia, IN, Column (b):
Of the total 9 compressors only 3 were in operation in 2013, with a total of 665 horsepower, Column (c).

Doe Run - Brandenburg, KY and Laconia, IN, Column (e):
Of the total amount, $10,791 is gas and $140,959 is electricity.

Doe Run - Brandenburg, KY and Laconia, IN, Column (j):
Station Peak not applicable for field compressors.

Muldraugh - Muldraugh, KY, Column(j):
Station Peak not applicable for field compressors.

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Storage Projects (Ref Page: 512)

	Gas Belonging to Respondent MCF (b)	Gas Belonging to Others MCF (c)	Total MCF (d)
Storage Operations (in MCF)			
Gas Delivered to Storage			
January	0	0	0
February	0	0	0
March	0	0	0
April	0	0	0
May	0	0	0
June	1,401,161	0	0
July	2,768,655	0	0
August	2,790,552	0	0
September	2,777,536	0	0
October	2,172,502	0	0
November	372,769	0	0
December	159,199	0	0
Total	12,442,374	0	0
Gas Withdrawn from Storage			
January	3,227,530	0	0
February	2,847,162	0	0
March	1,823,938	0	0
April	850,753	0	0
May	278,590	0	0
June	1,063	0	0
July	720	0	0
August	641	0	0
September	615	0	0
October	6,456	0	0
November	828,358	0	0
December	2,077,785	0	0
Total	11,943,611	0	0

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Gas Storage Projects (cont) (Ref Page: 513)

	Total Amount (b)	Date
Storage Operations		
Top or Working Gas End of Year	11,558,382	
Cushion Gas (Including native gas)	10,810,000	
Total Gas in Reservoir	22,368,382	
Certified Storage Capacity	25,900,000	
Number of Injection - Withdrawal Wells	355	
Number of Obsevation Wells	134	
Maximum Days Withdrawal from Storage	183,732	
Date of Maximum Days Withdrawal		01/25/2013
LNG Terminal Companies (MCF)		
Number of Tanks		
Capacity of Tanks		
LNG Volume		
Received at Ship Rail		
Transferred to Tanks		
Withdrawn from Tanks		
Boil Off Vaporization Loss		

Note:
Cushion gas includes non-current base gas of 2,930,000 Mcf (Account 117).

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Transmission Lines (Ref Page: 514)

Designation of Line or Group of Lines (a)	* (b)	Total Miles of Pipe (c)
Western Kentucky Line		49
Magnolia Line		122
Calvary Line		57
Elder Park Line		27
Total		255

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Transmission System Peak Deliveries (Ref Page: 518)

	Description	MCF Gas to Interstate Pipelines (b)	MCF Gas to Others (c)	Total (d)
Section A: Single Day Peak Deliveries				
Date	January 6, 2014			
Volumes of Gas Transported				
No-Notice Transportation		0	170,000	0
Other Firm Transportation		0	39,000	0
Interruptible Transportation		0	0	0
Other (Describe)				
	End-Use Transportation	0	70,000	0
Total		0	279,000	0
Volumes of gas Withdrawn form Storage under Storage Contracts				
No-Notice Storage		0	12,000	0
Other Firm Storage		0	0	0
Interruptible Storage		0	0	0
Other (Describe)				
		0	0	0
Total		0	12,000	0
Other Operational Activities				
Gas Withdrawn from Storage for System Operations		0	268,000	0
Reduction in Line Pack				
Other (Describe)				
Total		0	268,000	0
Section B: Consecutive Three-Day Peak Deliveries				
Dates:	January 21, 22, 23, 2014			
Volumes of Gas Transported				
No-Notice Transportation		0	457,000	0
Other Firm Transportation		0	105,000	0
Interruptible Transportation		0	0	0
Other (Describe)				
	End-Use Transportation	0	219,000	0

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Transmission System Peak Deliveries (Ref Page: 518)

Description	MCF Gas to Interstate Pipelines (b)	MCF Gas to Others (c)	Total (d)
Total	0	781,000	0
Volumes of Gas Withdrawn from Storage under Storage Contacts			
No-Notice Storage	0	98,000	0
Other Firm Storage	0	0	0
Interruptible Storage	0	0	0
Other (Describe)			
Total	0	98,000	0
Other Operational Activities			
Gas Withdrawn from Storage for System Operations	0	501,000	0
Reduction in Line Pack			
Other (Describe)			
Total	0	501,000	0

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

Auxiliary Peaking Facilities (Ref Page: 519)

Location (a)	Type (b)	Max Daily Delivery Capacity MCF (c)	Cost of Facility (d)	Operated on Date Highest Trans Peak Del? (yes/no)
Muldraugh - Meade County, KY	Underground Storage	220,000	$32,023,380.00	Yes
Doe Run - Meade Co., KY and Harrison Co., IN	Underground Storage	51,885	$17,372,007.00	Yes
Magnolia - Green, Hart and Larue Counties, KY	Underground Storage	55,185	$31,573,209.00	Yes
Center - Metcalfe, Green and Barren Counties, KY	Underground Storage	11,082	$10,444,386.00	Yes
Canmer - Hart and Green Counties, KY		0	$430,631.00	
Flint Hill - Hardin County, KY		0	$273,275.00	
Total		326,267	$92,116,888.00	
		0	$0.00	
		0	$0.00	
		0	$0.00	
		0	$0.00	
		0	$0.00	
		0	$0.00	
		0	$0.00	
		0	$0.00	
		0	$0.00	

Note:
Gas fields at Canmer and Flint Hill have been retired. These facilities are currently used in other gas-system operations.

Due to pipeline and compressor station capacity and multiple fields discharging into one pipeline system, total Max Daily Delivery Capacity has been estimated, even though individual fields may have greater deliverability than shown, and may aggregate to a higher total, especially earlier in the season when operated independently.

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Gas Account - Natural Gas (Ref Page: 520)

Description		Amt MCF
GAS RECEIVED		
Gas Purchases (800-805)		36,523,896
Gas of Others received for Gathering (ref pg 303) (489.1)		
Gas of Others Received for Transmission (Ref pg 305) (489.2)		
Gas of Others Received for Distrubution (ref pg 301) (489.3)		12,639,239
Gas of Others Received for Contract Storage (Ref Pg 307) (489.4)		
Exchanged Gas Received from Others (Ref Pg 328) (806)		3,415,956
Gas Received as Imbalances (Ref Pg 328) (806)		
Receipts of Respondent`s Gas Transported by Others (Ref pg 332) (858)		
Other Gas Withdrawn from Storage (Explain)		11,943,611
Gas Received from Shippers as Compressor Station Fuel		
Gas Received from Shippers as Lost and Unaccounted for		
Other Reciepts (Specify)		
Total Receipts		64,522,702
GAS DELIVERED		
Gas Sales (480-484)		34,260,587
Deliveries of gas Gathered for Others (Ref pg 303) (489.1)		
Deliveries of Gas Transported for Others (Ref Pg 305) (489.2)		319,936
Deliveries of Gas Distributed for Others (Ref Pg 301) (489.3)		11,988,840
Deliveries of Contract Storage gas (Ref Pg 307) (489.4)		
Exchange Gas Delivered to Others (Ref Pg 328) (806)		3,471,946
Gas Delivered as Imbalances (Ref Pg 328) (806)		
Deliveries of Gas to Others for Transportation (Ref Pg 332) (858)		
Other Gas Delivered to Storage (Explain)		12,442,374
Gas Used for Compressor Station Fuel (509)		135,604
Other Deliveries (Specify)		
	Duplicate Charges (Gas Department)	143,033
	Gas Used for Other Utility Operations	36,238
	Lost & Unaccounted for on Gas Transports	1,130

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Gas Account - Natural Gas (Ref Page: 520)

Description	Amt MCF
28. Total Deliveries	62,799,688
GAS UNACCOUNTED FOR	
Production System Losses	
Gathering System Losses	
Transmission System Losses	
Distribution System Losses	
Storage System Losses	440,383
Other Losses (Specify)	
Sales and Transport	1,777,631
36. Total Unaccounted For	2,218,014
Total Deliveries and Unaccounted For For (Line 28 and 36)	65,017,702

Note:
Gas purchases include volumes recorded in Natural Gas Transmission Line Purchases (803).

Transmission gas is reported on the following lines:
Gas of Others Received for Distribution - 12,639,239 Mcf
Deliveries of Gas Transported for Others - 319,936 Mcf
Deliveries of Gas Distributed for Others - 11,988,840 Mcf

Other Gas Withdrawn from Storage represents net withdrawal of gas from storage recorded in Gas Withdrawn from Storage--Debit (808.1).

Other Gas Delivered to Storage represents net deliveries of gas to storage recorded in Gas Delivered to Storage--Credit (808.2).

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CheckList

Item	Value 1	Value 2	Agree	Explain
Balance Sheet (Ref pg 110)				
Utility Plant agrees with Sched Summary of Utility Plant (Ref pg 200) Line 13. Total Utility Plant less Line 11. Construction Work In Progress	5067913274.00	5067913274.00	OK	
Line 3. Construction Work In Progress agrees with Sched Summary of Utility Plant (Ref pg 200) Line 11. Construction Work In Progress	651432116.00	651432116.00	OK	
Line 5. Accum. Prov for Depr and Amort Depl agrees with Sched Summary of Utility Plant (Ref Pg 200) Lines 14. Accum. Prov for Depr and Amort Depl	2304132232.00	2304132232.00	OK	
Line 5. Accum. Prov for Depr and Amort Depl agrees with Sched Summary of Utility Plant (Ref Pg 200) Lines 33. Total Accumulated Provisions	2304132232.00	2304132232.00	OK	
Line 6. Net Utility Plant agrees with Sched Summary of Utility Plant (Ref Pg 200) Lines 15. Net Utility Plant	3415213158.00	3415213158.00	OK	
Line 11. Utility Plant Adjustments are supported by Submitted Financial Statements as requested on Ref Pg 122				
Line 12. Gas Stored-Base Gas (117.1) agrees with Sched Gas Stored Accounts (Ref Pg 220) Line Balance at End of Year Column 117.1 (b)	2139990.00	2139990.00	OK	
Line 14. Gas Stored Underground - Non Current (117.3) agrees with Sched Gas Stored Accounts (Ref Pg 220) Line Balance at End of Year Column 117.4 (d)	0.0000	0.0000	OK	
Line 15. Gas Owned to System Gas (117.4) agrees with Sched Gas Stored Accounts (Ref Pg 220) Line Balance at End of Year Column 117.4 (e)	0.0000	0.0000	OK	
Line 17. Investments in Subsidiary Companies agrees with Sched Investments in Subsidiary Companies 123.1 (Ref Pg 224) Line Total Column Amt of Investment (g)	594286.00	594286.00	OK	
Line 47. Gas Stored Underground - Current (164.1) agrees with Sched Gas Stored Accounts (Ref Pg 220) Col 164.1 (f)	47546888.00	47546888.00	OK	

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CheckList

Item	Value 1	Value 2	Agree	Explain
Line 48. Liquefied Nat Gas Stored and Held (164.3) agrees with Sched Gas Stored Accounts (Ref Pg 220) Sum of Cols 164.2 and 164.3	0.0000	0.0000	OK	
Line 49. Prepayments agrees with Sched Prepayments (Ref Pg 230)	5125670.00	5125670.00	OK	
Line 58. Extraordinary Property Losses agrees with Sched Extraordinary Property Losses (Ref Pg 230)	0.0000	0.0000	OK	
Line 59 Unrecovered Plant and Regulatory Study Costs agrees with Sched Unrecovered Plant and Regulatory Study Costs (Ref Pg 230)	0.0000	0.0000	OK	
Line 65 Miscellaneous Deferred Debits agrees with Sched Miscellaneous Deferred Debits (Ref Pg 233)	503728950.00	503728950.00	OK	
Line 69 Accumulated Deferred Income Taxes agrees with Sched Accumulated Deferred Income Taxes (Ref Pg 234) Total Acct 190	174804497.00	174804497.00	OK	
Comparative Balance Sheet (Liabilities and Other Credits) (Ref Pg 112)				
Line 2. Common Stock Issued agrees with Sched Capital Stock (Ref Pg 250) Line Total Common Stock Col (f)	425170424.00	425170424.00	OK	
Line 3. Preferred Stock Issued agrees with Sched Capital Stock (Ref Pg 250) Line Total Preferred Stock Col (f)	0.0000	0.0000	OK	
Line 4. Capital Stock Subscribed agrees with Sched Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Pg 252) Line Total Capital Stock Subscribed Col (d)	0.0000	0	OK	
Line 5. Stock Liability for Conversion agrees with Sched Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Pg 252) Line Total Stock Liability for Conversion	0.0000	0	OK	
Line 6. Premium on Capital Stock agrees with Sched Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Pg 252) Line Total Premium on Capital Stock	0.0000	0	OK	

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CheckList

Item	Value 1	Value 2	Agree	Explain
Line 7. Other Paid-in Capital Stock agrees with Sched Other Paid in Capital(Ref Pg 253) Line Total	1363667368.00	1363667368.00	OK	
Line 8 . Installmnts Recvd Capital Stk agrees with Sched Capital Stock Subscribed, Liability for Conversion Premium and Installments Received (Ref Pg 252) Line Tot Inst. Recvd on Capital Stock	0.0000	0	OK	
Line 9. Discount on Capital Stock agrees with Sched Discount on Capital Stock Acct 213 (Ref Pg 254) Line Total	0.0000	0.0000	OK	
Line 10. Capital Stock Expense agrees with Sched Capital Stock Expense Acct 214 (Ref Pg 254) Line Total	835889.00	835889.00	OK	
Line 11 Retained Earnings agrees with Statement of Retained Earnings for the Year (Ref Pg 118) Line 19. Total Retained Earnings	172457991.00	172457991.00	OK	
Line 12. Unappropriated Undistributed Subsidiary Earnings agrees with Statement of Retained Earnings for the Year (Ref Pg 118) Line 24. Balance End of Year	0.0000	0	OK	
Line 13. Reacquired Capital Stock agrees with Capital Stock (Ref Pg 250) Line Total col Acct 217 (h)	0.0000	0.0000	OK	
Line 39. Taxes Accrued agrees with Sched Taxes Accrued, Prepaid and Charged (Ref Pg 263) Line Total Col Acct 236 (g)	11474666.00	11474666.00	OK	
Line 45. Misc Current and Accrued Liabilities agrees with Sched Misc Current and Accured Liabilities (Ref Pg 268) Line Total	18912401.00	18912401.00	OK	
Line 52. Other Deferred Credits agrees with Sched Other Deferred Credits (Ref Pg 269) Line Total	17863555.00	17863555.00	OK	
Income Statement (Ref Pg 114)				
Line 2. Gas Operating Revenues agrees with Sched Gas Operating Revenues (Ref Pg 300) Line Total Col (h)	324221274.00	324221274.00	OK	

22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

CheckList

Item	Value 1	Value 2	Agree	Explain
Sum of Lines 4 and 5 Operation and Maint Expenses agrees with Sched Gas Operation and Maintenance (Ref Pg 335) Line Total Gas O and M Expenses	223555940.00	223555940.00	OK	
Line 6. Depreciation Exp (403) agrees with Sched Depreciation, Depletion and Amort (Ref Pg 336) Line Total Col Depreciation (b)	23748693.00	23748693.00	OK	
Line 7. Amort and Depl (404-405) agrees with Sched Depreciation, Depletion and Amort (Ref Pg 336) Line Total Sum of Cols (c-f)	2305153.00	2305153.0000	OK	
Sum of Lines 13,14 and 15. Taxes (408.1-409.1) agrees with Sched Taxes Accr, Prepd and Charged (Ref Pg 262) Line Total Col (j)	22367304.00	22367304.00	OK	
Line 16. Provision for Deferred Income Taxes (410.1) agrees with SUM OF Acct 190 (Ref Pg 234) Col c , Acct 282 (Ref Pg 274) Col c and Acct 282 (Ref Pg 276) Col c	211251945.00	211251945.00	OK	
Line 17. (Less) Provision for Deferred Income Taxes (411.1) agrees with SUM OF Acct 190 (Ref Pg 234) Col d , Acct 282 (Ref Pg 274) Col d and Acct 282 (Ref Pg 276) Col d	183189299.00	183189299.00	OK	
Income Statement (Ref Pg 116)				
Sum of Lines 48,49 and 50 agrees with Sched Taxes Accr, Prepd and Charged (Ref Pg 262) Line Total Taxes Other Than Income Col (l)	-1441719.00	-1441719.00	OK	
Line 49. Provision for Deferred Inc. Taxes agrees with Sched Accumulated Deferred Income Taxes (Ref Pg 234) Line Total Acct 190 Col 410.2 (e)	205595.00	982.00	NO	The difference between the Provision for Deferred Income Taxes per the Income Statement and the Schedule of Accumulated Deferred Income Taxes of $204,613 is in Account 283 (Ref pg 276).
Line 52. (Less) Provision for Deferred Inc. Taxes CR agrees with Sched Accumulated Deferred Income Taxes (Ref Pg 234) Line Total Acct 190 Col 411.2 (f)	19165.00	19162.00	NO	The difference between the Provision for Deferred Income Taxes per the Income Statement and the Schedule of Accumulated Deferred Income Taxes of $3 is in Account 283 (Ref pg 276).
Line 70. Income Taxes - Federal and Other agrees with Sched Taxes Accr, Prepd and Charged (Ref Pg 262) Col 409.3 (m) Sum of Lines Total Income Taxes Federal and Other	0.0000	0.0000	OK	

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22200500 Louisville Gas and Electric Company 01/01/2013 - 12/31/2013

CheckList

Item	Value 1	Value 2	Agree	Explain
Summary of Utility Plant and Accumulated Provisions for Depreciation Amortization and Depletion (Ref Pg 200)				
Line 8. Total Utility Plant agrees with Sched Gas Plant in Service (Ref Pg 206) Line Total Gas Plant in Service Col (g)	842651317.00	842651317.00	OK	
Line 10. Held for Future Use agrees with Sched Gas Plant Held for Future Use (Ref Pg 214) Line Total	0.0000	0	OK	
Line 11. Construction Work in Progress agrees with Sched Construction Work in Progress (Ref Pg 216) Line Total	55354723.00	55354723.00	OK	
Line 18. Depreciation agrees with Sched Accumulated Provision for Depreciation of Gas Utility Plant (Ref Pg 219) Line Balance at End of Year	261129697.00	261129697.00	OK	
Statement of Retained Earnings for the Year (Ref Pg 118)				
Line 10 Total Dividends Declared - Preferred Stock agrees with Statement of Cash Flows (Ref Pg 120) Line 68. Dividends on Preferred Stock	0	0	OK	
Line 11. Total Dividends Declared - Common Stock agrees with Statement of Cash Flows (Ref Pg 120) Line 69. Dividends on Common Stock	-99000000.00	-99000000.00	OK	
Miscellaneous General Expenses (Ref Pg 335)				
Line Total agrees with Sched Gas Operation and Maintenance (Ref Pg 323) Line Miscellaneous General Expenses	369526.00	369526.00	OK	

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OATH

Commonwealth of Kentucky)
) ss:
County of Jefferson)

Kent W. Blake makes oath and says
(Name of Officer)

that he/she is Chief Financial Officer of
(Official title of officer)

Louisville Gas and Electric Company
(Exact legal title or name of respondent)

that it is his/her duty to have supervision over the books of account of the respondent and to control the manner in which such books are kept; that he/she knows that such books have, during the period covered by the foregoing report, been kept in good faith in accordance with the accounting and other orders of the Public Service Commission of Kentucky, effective during the said period; that he/she has carefully examined the said report and to have the best of his/her knowledge and belief the entries contained in the said report have, so far as they relate to matters of account, been accurately taken from the said books of account and are in exact accordance therewith; that he/she believes that all other statements of fact contained in the said report are true; and that the said report is a correct and complete statement of the business and affairs of the above-named respondent during the period of time from and including

January 1, 20 13, to and including December 31, 20 13

KtWBlake
(Signature of Officer)

subscribed and sworn to before me, a Notary Public, in and for the State and County named in the above this 24th day of March, 20 14

(Apply Seal Here)

My Commission expires November 9, 2014

Tammy J. Ely
(Signature of officer authorized to administer oath)

[Persons making willful false statements in this report may be punished by fine or imprisonment under KRS 523.040 and 523.100.]

Notes to Financial Statements

Per Kentucky PSC Order No. 2008-00007, attached are the “Notes to Financial Statements” for Louisville Gas & Electric Company as reported in the FERC Form No. 1 for the period ended December 31, 2013.

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 services to LKE and its subsidiaries.

PPL **-** PPL Corporation, the parent holding company of LKE and other subsidiaries.

Other terms and abbreviations

401(h) account **-** A sub-account established within a qualified pension trust to provide for the payment of retiree medical costs.

AOCI **-** accumulated other comprehensive income or loss.

ARO **-** asset retirement obligation.

BREC **-** Big Rivers Electric Corporation, a power-generating rural electric cooperative in western Kentucky.

Cane Run Unit 7 **-** a natural gas combined-cycle unit under construction in Kentucky, jointly owned by LG&E and KU, which is expected to provide additional electric generating capacity of 640 MW (141 MW and 499 MW to LG&E and KU) in 2015.

CAIR **-** the EPA's Clean Air Interstate Rule.

CCR **-** Coal Combustion Residuals. 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.

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.

CSAPR **-** Cross-State Air Pollution Rule.

Dodd-Frank Act **-** the Dodd-Frank Wall Street Reform and Consumer Protection Act that was signed into law in July 2010.

DSM **-** Demand Side Management. Pursuant to Kentucky Revised Statute 278.285, the KPSC may determine the reasonableness of DSM plans proposed by any utility under its jurisdiction. Proposed DSM mechanisms may seek full recovery of costs and revenues lost by implementing DSM programs and/or incentives designed to provide financial rewards to the utility for implementing cost-effective DSM programs. The cost of such programs shall be assigned only to the class or classes of customers which benefit from the programs.

EBPB **-** Employee Benefit Plan Board. The administrator of PPL's qualified retirement plans, which is charged with the fiduciary responsibility to oversee and manage those plans and the investments associated with those plans.

ECR **-** Environmental Cost Recovery. Pursuant to Kentucky Revised Statute 278.183, 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.

EPA **-** Environmental Protection Agency, a U.S. government agency.

E.W. Brown **-** a generating station in Kentucky with capacity of 1,594 MW.

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.

Fitch **-** Fitch, Inc., a credit rating agency.

GAAP **-** Generally Accepted Accounting Principles in the U.S.

GHG **-** greenhouse gas(es).

GLT **-** Gas Line Tracker. The KPSC approved LG&E's recovery of costs associated with gas service lines, gas risers, leak mitigation, and gas main replacements. Rate recovery became effective January 1, 2013.

Green River Unit 5 **-** a natural gas combined-cycle unit proposed to be built in Kentucky, jointly owned by LG&E and KU, which is expected to provide additional electric generating capacity of 700MW (280 MW and 420 MW to LG&E and KU) in 2018.

IBEW – International Brotherhood of Electrical Workers

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.

kWh **-** kilowatt-hour, basic unit of electrical energy.

LG&E 2010 Mortgage Indenture **-** LG&E's indenture, dated as of October 1, 2010, to The Bank of New York Mellon, as trustee, as supplemented.

LIBOR **-** London Interbank Offered Rate.

MATS **-** Mercury and Air Toxics Standards.

Moody's **-** Moody's Investors Service, Inc., a credit rating agency.

MW **-** megawatt, one thousand kilowatts.

MWh **-** megawatt-hour, one thousand kilowatt-hours.

NERC **-** North American Electric Reliability Corporation.

NGCC **-** Natural gas-fired combined-cycle turbine.

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 LKE indirectly owns an 8.13% interest (consists of LG&E's 5.63% and KU's 2.50% interests), which is accounted for as a cost-method investment. OVEC owns and operates two coal-fired power plants, the Kyger Creek plant in Ohio and the Clifty Creek plant in Indiana, with combined summer rating capacities of 2,120 MW.

PJM **-** PJM Interconnection, L.L.C., operator of the electricity transmission network and electric energy market in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

PP&E **-** property, plant and equipment.

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.

S&P **-** Standard & Poor's Ratings Services, a credit rating agency.

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.

TC2 **-** Trimble County Unit 2, a coal-fired plant located in Kentucky with a net summer capacity of 732 MW. LKE indirectly owns a 75% interest (consists of LG&E's 14.25% and KU's 60.75% interests) in TC2, or 549 MW of the capacity.

Tolling agreement **-** agreement whereby the owner of an electricity generating facility agrees to use that facility to convert fuel provided by a third party into electricity for delivery back to the third party.

VEBA **-** Voluntary Employee Benefit Association Trust, accounts for health and welfare plans for future benefit payments for employees, retirees or their beneficiaries.

VIE **-** variable interest entity.

Volumetric risk **-** the risk that the actual load volumes provided under full-requirement arrangements could vary significantly from forecasted volumes.

As permitted by the FERC for the Year Ended December 31, 2013 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, 2013, which was filed with the SEC on February 24, 2014. Accordingly, these Notes do not reflect updated information since this filing date.

NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

General

Capitalized terms and abbreviations appearing in the notes to financial statements are defined in the glossary. Dollars are in millions, unless otherwise noted.

Business and Consolidation

LG&E is engaged in the regulated generation, transmission, distribution and sale of electricity. LG&E also engages in the regulated distribution and sale of natural gas.

The financial statements of LG&E include the company's own accounts as well as the accounts of all entities in which the company has a controlling financial interest. Entities for which a controlling financial interest is not demonstrated through voting interests are evaluated based on accounting guidance for VIEs. LG&E has no controlling interest in a VIE. Investments in entities in which a company has the ability to exercise significant influence but does not have a controlling financial interest are accounted for under the equity method. All other investments are carried at cost or fair value. All significant intercompany transactions have been eliminated. Any noncontrolling interests are reflected in the financial statements.

The financial statements of LG&E include its share of any undivided interests in jointly owned facilities, as well as its share of the related operating costs of those facilities. See Note 9 for additional information.

Regulation

LG&E is a cost-based rate-regulated utility for which rates are set by regulators to enable LG&E to recover the costs of providing electric or gas service and to provide a reasonable return to shareholders. Rates are generally established based on a test period adjusted to exclude unusual or nonrecurring items. As a result, the financial statements are subject to the accounting for certain types of regulation as prescribed by GAAP and reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery of underlying costs is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise currently be charged to expense. Regulatory liabilities are recognized for amounts expected to be returned through future regulated customer rates. In certain cases, regulatory liabilities are recorded based on an understanding or agreement with the regulator that rates have been set to recover costs that are expected to be incurred in the future, and the regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. The accounting for regulatory assets and 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

The system of accounts for LG&E is maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the applicable state regulatory commissions.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Loss Accruals

Potential losses are accrued when (1) information is available that indicates it is "probable" that a loss has been incurred, given the likelihood of the uncertain future events and (2) the amount of the loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." LG&E continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events. Loss accruals for environmental remediation are discounted when appropriate.

The accrual of contingencies that might result in gains is not recorded, unless realization is assured.

Price Risk Management

Energy and energy-related contracts are used to hedge the variability of expected cash flows associated with the generating units and marketing activities. Interest rate contracts are used to hedge exposures to changes in the fair value of debt instruments and to hedge exposures to variability in expected cash flows associated with existing 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 energy and energy-related contracts meet the definition of a derivative, while others do 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 energy contracts have been excluded from the requirements of derivative accounting treatment because NPNS has been elected. These contracts are accounted for using accrual accounting. All other contracts that have been classified as derivative contracts are reflected on the Balance Sheets at fair value. These contracts are recorded as "Price risk management assets" and "Price risk management liabilities" on the Balance Sheets. 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."

Energy and energy-related contracts are assigned a strategy and accounting classification. Processes exist that allow for subsequent review and validation of the contract information. See Note 14 for more information. The accounting department provides the traders and the risk management department with guidelines on appropriate accounting classifications for various contract types and strategies. Some examples of these guidelines include, but are not limited to:

- Physical coal, limestone, lime, uranium, electric transmission, gas transportation, gas storage and renewable energy credit contracts not traded on an exchange are not derivatives due to the lack of net settlement provisions.

- Only contracts where physical delivery is deemed probable throughout the entire term of the contract can qualify for NPNS.

- Physical transactions that permit cash settlement and financial transactions do not qualify for NPNS because physical delivery cannot be asserted; however, these transactions can receive cash flow hedge treatment if they effectively hedge the volatility in the future cash flows for energy-related commodities.

- Certain purchased option contracts or net purchased option collars may receive cash flow hedge treatment.

- Derivative transactions that do not qualify for NPNS or cash flow hedge treatment, or for which NPNS or cash flow hedge treatment is not elected, are recorded at fair value through earnings.

A similar process is also followed by the treasury department as it relates to interest rate derivatives. Examples of accounting guidelines provided to the treasury department staff include, but are not limited to:

- Transactions to lock in an interest rate prior to a debt issuance can be designated as cash flow hedges; to the extent the forecasted debt issuances remain probable of occurring.

- Derivative transactions that do not qualify for cash flow or net investment hedge treatment are marked to fair value through earnings.

- Derivative transactions may be marked to fair value through regulatory assets/liabilities if approved by the appropriate regulatory body. These transactions generally include the effect of interest rate swaps that are included in customer rates.

Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing activities on the Statements of Cash Flows, depending on the classification of the hedged items.

LG&E has elected not to offset net derivative positions against the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

See Notes 13 and 14 for additional information on derivatives.

Revenue

Revenue Recognition

Operating revenues, except for certain energy and energy-related contracts that meet the definition of derivative instruments and "Energy-related businesses," are recorded based on energy deliveries through the end of the calendar month. Unbilled retail revenues result because customers' meters are read and bills are rendered throughout the month, rather than all being read at the end of the month. Unbilled revenues for a month are calculated by multiplying an estimate of unbilled kWh by the estimated average cents per kWh. Unbilled wholesale energy revenues are recorded at month-end to reflect estimated amounts until actual dollars and MWhs are confirmed and invoiced. 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 adjusted for an allowance for doubtful accounts. Accounts receivable that are acquired are initially recorded at fair value on the date of acquisition.

Allowance for Doubtful Accounts

Accounts receivable collectability is evaluated using a combination of factors, including past due status based on contractual terms, trends in write-offs, the age of the receivable, counterparty creditworthiness and economic conditions. Specific events, such as bankruptcies, are also considered. Adjustments to the allowance for doubtful accounts are made when necessary based on the results of analysis, the aging of receivables and historical and industry trends.

Accounts receivable are written off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable previously written off are recorded when it is known they will be received.

The changes in the allowance for doubtful accounts at December 31 were:

		Additions			
	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
2013	$ 1	$ 2	$ 1	$ 2	$ 2
2012	2	2	-	3	1

(a) Primarily related to capital projects, thus the provision was recorded as an adjustment to construction work in progress.

(b) 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.

Restricted Cash and Cash Equivalents

Bank deposits and other cash equivalents that are restricted by agreement or that have been clearly designated for a specific purpose are classified as restricted cash and cash equivalents. The change in restricted cash and cash equivalents is reported as an investing activity on the Statements of Cash Flows. On the Balance Sheets, the current portion of restricted cash and cash equivalents is shown in "Other current assets" while the noncurrent portion is included in "Other noncurrent assets".

LG&E had restricted cash and cash equivalents for cash collateral posted to counterparties of $22 million and $32 million at December 31, 2013 and 2012.

Fair Value Measurements

LG&E values certain financial and nonfinancial assets and liabilities at fair value. Generally, the most significant fair value measurements relate to price risk management assets and liabilities and cash and cash equivalents. LG&E uses, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques and option-pricing models) and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

LG&E classifies fair value measurements within one of three levels in the fair value hierarchy. The level assigned to a fair value measurement is based on the lowest level input that is significant to the fair value measurement in its entirety. The three levels of the fair value hierarchy are as follows:

- **Level 1 -** quoted prices (unadjusted) in active markets for identical assets or liabilities that are accessible at the measurement date. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

- **Level 2 -** inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for substantially the full term of the asset or liability.

- **Level 3 -** unobservable inputs that management believes are predicated on the assumptions market participants would use to measure the asset or liability at fair value.

Assessing the significance of a particular input requires judgment that considers factors specific to the asset or liability. As such, LG&E's assessment of the significance of a particular input may affect how the assets and liabilities are classified within the fair value hierarchy.

Investments

Generally, the original maturity date of an investment and management's intent and ability to sell an investment prior to its original maturity determine the classification of investments as either short-term or long-term. Investments that would otherwise be classified as short-term, but are restricted as to withdrawal or use for other than current operations or are clearly designated for expenditure in the acquisition or construction of noncurrent assets or for the liquidation of long-term debts, are classified as long-term.

Short-term Investments

Short-term investments generally include certain deposits as well as securities that are considered highly liquid or provide for periodic reset of interest rates. Investments with original maturities greater than three months and less than a year, as well as investments with original maturities of greater than a year that management has the ability and intent to sell within a year, are included in "Other current assets" on the Balance Sheets.

Cost Method Investment

LG&E has an investment in OVEC, which is accounted for using the cost method. The investment is recorded in "Other noncurrent assets" on the Balance Sheets. LG&E and 11 other electric utilities are equity owners of OVEC. OVEC's power is currently supplied to LG&E and 12 other companies affiliated with the various owners. LG&E owns 5.63% of OVEC's common stock. Pursuant to a power purchase agreement, LG&E is contractually entitled to its ownership percentage of OVEC's output, which is approximately 120 MW.

LG&E's investment in OVEC is not significant. The direct exposure to loss as a result of LG&E's involvement with OVEC is generally limited to the value of its investment; however, LG&E may be conditionally responsible for a pro-rata share of certain OVEC obligations. As part of PPL's acquisition of LKE, the value of the power purchase contract was recorded as an intangible asset with an offsetting regulatory liability, both of which are being amortized using the units-of-production method until March 2026, the expiration date of the agreement. See Notes 10 and 15 for additional discussion on the power purchase agreement.

Long-Lived and Intangible Assets

Property, Plant and Equipment

PP&E is recorded at original cost, unless impaired. PP&E acquired in business combinations is recorded at fair value at the time of acquisition, which establishes its original cost. 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 replacements are charged to expense as incurred. LG&E records costs associated with planned major maintenance projects in the period in which the costs are incurred. No costs associated with planned major maintenance projects are accrued in advance of the period in which the work is performed. LG&E accrues costs of removal net of estimated salvage value through depreciation, which is included in the calculation of customer rates over the assets' depreciable lives in accordance with regulatory practices. Cost of removal amounts accrued through depreciation rates are accumulated as a regulatory liability until the removal costs are incurred. See "Asset Retirement Obligations" below and Note 4 for additional information.

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. LG&E’s weighted-average rates of depreciation for regulated utility plant were 4.52% and 4.91% at December 31, 2013 and 2012.

The KPSC approved new lower depreciation rates for LG&E as part of the rate-case settlement agreement reached in November 2012. The new rates became effective January 1, 2013 and resulted in lower depreciation of approximately $8 million in 2013, exclusive of net additions to PP&E.

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, LG&E considers the expected use of the asset; the expected useful life of other assets to which the useful life of the intangible asset may relate; legal, regulatory, or contractual provisions that may limit the useful life; the company's historical experience as evidence of its ability to support renewal or extension; the effects of obsolescence, demand, competition, and other economic factors; and the level of maintenance expenditures required to obtain the expected future cash flows from the asset.

LG&E accounts for emission allowances as intangible assets. LG&E is allocated emission allowances by states based on its generation facilities' historical emissions experience, and have purchased emission allowances generally when it is expected that additional allowances will be needed. The carrying value of allocated emission allowances is initially recorded at zero value and purchased allowances are initially recorded based on their purchase price. When consumed or sold, emission allowances are removed from the Balance Sheets at their weighted-average carrying value. Since the economic benefits of emission allowances are not diminished until they are consumed, emission allowances are not amortized; rather, they are expensed when consumed or a gain or loss is recognized when sold. Such expense is included in "Fuel" on the Statements of Income. Gains and losses on the sale of emission allowances are included in "Other operation and maintenance" on the Statements of Income.

Asset Impairment (Excluding Investments)

LG&E reviews long-lived assets that are subject to depreciation or amortization, including finite-lived intangibles, for impairment when events or circumstances indicate carrying amounts may not be recoverable. A long-lived asset classified as held and used is impaired when the carrying amount of the asset exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If impaired, the asset's carrying value is written down to its fair value.

A long-lived asset classified as held for sale is impaired when the carrying amount of the asset (disposal group) exceeds its fair value less cost to sell. If impaired, the asset's (disposal group's) carrying value is written down to its fair value less cost to sell.

Goodwill is reviewed for impairment at the reporting unit level annually or more frequently when events or circumstances indicate that the carrying amount of a reporting unit may be greater than the unit's fair value. Additionally, goodwill must be tested for impairment in circumstances when a portion of goodwill has been allocated to a business to be disposed. LG&E is a single reporting unit.

LG&E 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.

LG&E elected to perform the qualitative step zero evaluation of goodwill in the fourth quarter of 2013 and determined that it was not more likely than not that the fair value of its goodwill was less than its carrying value.

Asset Retirement Obligations

LG&E records liabilities to reflect various legal obligations associated with the retirement of long-lived assets. Initially, this obligation is measured at fair value and offset with an increase in the value of the capitalized asset, which is depreciated over the asset's useful life. Until the obligation is settled, the liability is increased through the recognition of accretion expense classified within "Other operation and maintenance" on the Statements of Income to reflect changes in the obligation due to the passage of time. The accretion and depreciation expenses recorded by LG&E are recorded as a regulatory asset, such that there is no earnings impact.

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 16 for additional information on AROs.

Compensation and Benefits

Defined Benefits

LG&E sponsors and participates in defined benefit pension and other postretirement plans. The plans LG&E participates in are sponsored by LKE. LKE allocates a portion of the liability and net periodic defined benefit pension and other postretirement costs of certain plans to LG&E based on its participation. 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.

LG&E and LKE use an accelerated amortization method for the recognition of gains and losses for its defined benefit pension plans. Under the accelerated method, actuarial gains and losses in excess of 30% of the plan's projected benefit obligation are amortized on a straight-line basis over one-half of the expected average remaining service of active plan participants. Actuarial gains and losses in excess of 10% of the greater of the plan's projected benefit obligation or the market-related value of plan assets and less than 30% of the plan's projected benefit obligation are amortized on a straight-line basis over the expected average remaining service period of active plan participants.

See Note 8 for a discussion of defined benefits.

Taxes

Income Taxes

LG&E is included in PPL’s consolidated U.S. federal income tax return.

Significant management judgment is required in developing LG&E’s provision for income taxes, primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and 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. LG&E uses a two-step process to evaluate tax positions. The first step requires LG&E 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 LG&E to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact the financial statements of LG&E in 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.

LG&E records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. LG&E considers the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies in initially recording and subsequently reevaluating the need for valuation allowances. If LG&E determines that it is able to realize deferred tax assets in the future in excess of recorded net deferred tax assets, adjustments to the valuation allowances increase income by reducing tax expense in the period that such determination is made. Likewise, if LG&E determines that it is not able to realize all or part of net deferred tax assets in the future, adjustments to the valuation allowances would decrease income by increasing tax expense in the period that such determination is made.

LG&E defers investment tax credits when the credits are utilized and amortizes the deferred amounts over the average lives of the related assets.

LG&E recognizes interest and penalties in "Income Taxes" on its Statements of Income.

See Note 3 for additional discussion regarding income taxes.

The provision for LG&E’s deferred income taxes for regulated assets is based upon the ratemaking principles reflected in rates established by the 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."

The income tax provision for LG&E is calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if LG&E filed a separate return. Tax benefits are not shared between companies. A tax benefit inures only to the entity that gave rise to said benefit. The effect of PPL filing a consolidated tax return is taken into account in the settlement of current taxes and the recognition of deferred taxes. LG&E's intercompany tax receivables (payables) were $(8) million and $5 million at December 31, 2013 and 2012.

Taxes, Other Than Income

LG&E presents sales taxes in "Other current liabilities" on the Balance Sheets. These taxes are not separately 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

LG&E evaluates whether arrangements entered into contain leases for accounting purposes. See Note 7 for a discussion of arrangements under which LG&E is a lessee for accounting purposes.

Fuel, Materials and Supplies

Fuel, natural gas stored underground and materials and supplies are valued at the lower of cost or market using the average cost method. Fuel costs for electric generation are charged to expense as used. For LG&E, natural gas supply costs are charged to expense as delivered to the distribution system. See Note 4 for further discussion of the fuel adjustment clause and gas supply clause.

"Fuel, materials and supplies" on the Balance Sheets consisted of the following at December 31.

	2013	2012
Fuel	$ 64	$ 61
Natural gas stored underground (a)	48	42
Materials and supplies	42	39
Total	$ 154	$ 142

(a) The majority of LG&E's natural gas stored underground is held to serve retail customers

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.

New Accounting Guidance Adopted

Improving Disclosures about Offsetting Balance Sheet Items

Effective January 1, 2013, LG&E retrospectively adopted accounting guidance issued to enhance disclosures about derivative instruments that either (1) offset on the balance sheet or (2) are subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet.

The adoption of this guidance resulted in enhanced disclosures but did not have a significant impact on LG&E. See Note 14 for the new disclosures.

Testing Indefinite-Lived Intangible Assets for Impairment

Effective January 1, 2013, LG&E prospectively adopted accounting guidance that allows an entity to elect the option to first make a qualitative evaluation about the likelihood of an impairment of an indefinite-lived intangible asset. If, based on this assessment, the entity determines that it is more likely than not that the fair value of the indefinite-lived intangible asset exceeds the carrying amount, a quantitative impairment test does not need to be performed. If the entity concludes otherwise, a quantitative impairment test must be performed by determining the fair value of the asset and comparing it with the carrying value. The entity would record an impairment charge, if necessary.

The adoption of this guidance did not have a significant impact on LG&E.

2. Preferred Securities

LG&E is authorized to issue up to 1,720,000 shares of preferred stock at a $25 par value and 6,750,000 shares of preferred stock without par value. LG&E had no preferred stock issued or outstanding in 2013 or 2012.

3. Income and Other Taxes

The provision for LG&E's deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the KPSC and the FERC. The difference in the provision for deferred income taxes for regulated assets and 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.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Significant components of LG&E's deferred income tax assets and liabilities were as follows at December 31.

	2013	2012
Deferred Tax Assets		
Regulatory liabilities	$ 59	$ 54
Deferred investment tax credits	15	16
Income taxes due to customers	19	21
Other	28	9
Total deferred tax assets	121	100
Deferred Tax Liabilities		
Plant - net	585	526
Regulatory assets	83	86
Accrued pension costs	24	27
Other	8	9
Total deferred tax liabilities	700	648
Net deferred tax liability	$ 579	$ 548

LG&E expects to have adequate levels of taxable income to realize its recorded deferred income tax assets.

At December 31, 2013, LG&E had $10 million of federal net operating loss carryforwards that expire in 2032 and $22 million of state net operating loss carryforwards that expire in 2030.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Louisville Gas and Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Details of the components of income tax expense, a reconciliation of federal income taxes derived from statutory tax rates applied to "Income Before Income Taxes" to income taxes for reporting purposes, and details of "Taxes, other than income" at December 31 were:

	2013	2012
Income Tax Expense (Benefit)		
Current - Federal	$ 52	$ (2)
Current - State	16	3
Total Current Expense (Benefit)	68	1
Deferred - Federal	33	65
Deferred - State	(2)	6
Total Deferred Expense, excluding benefits of operating loss carryforwards	31	71
Investment tax credit, net - Federal	(2)	(3)
Tax benefit of operating loss carryforwards		
Deferred - Federal	(3)	-
Total Tax Benefit of Operating Loss Carryforwards	(3)	-
Total income tax expense	$ 94	$ 69
Total income tax expense - Federal	$ 80	$ 60
Total income tax expense - State	14	9
Total income tax expense	$ 94	$ 69

	2013	2012
Reconciliation of Income Taxes		
Federal income tax on Income Before Income Taxes at statutory tax rate - 35%	$ 90	$ 67
Increase (decrease) due to:		
State income taxes, net of federal income tax benefit	10	5
Amortization of investment tax credit	(2)	(3)
Other	(4)	-
Total increase	4	2
Total income tax expense	$ 94	$ 69
Effective income tax rate	36.6%	35.9%

	2013	2012
Taxes, other than income		
Property and other	$ 24	$ 23
Total	$ 24	$ 23

Unrecognized Tax Benefits

LG&E's unrecognized tax benefits and changes in those unrecognized tax benefits are insignificant at December 31, 2013 and 2012. At December 31, 2013, no significant changes in unrecognized tax benefits are projected over the next 12 months.

At December 31, the total unrecognized tax benefits and related indirect effects that, if recognized, would decrease the effective tax rate were insignificant.

At December 31, 2013 and 2012, receivable (payable) balances were recorded for interest related to tax positions. The amounts were insignificant. The interest expense (benefit) was recognized in income taxes. The amounts were insignificant.

The income tax provisions for LG&E are calculated in accordance with an intercompany tax sharing agreement which provides that taxable income be calculated as if each subsidiary filed a separate consolidated return. Based on this tax sharing agreement, LG&E indirectly files tax returns in two major tax jurisdictions. With few exceptions, at December 31, 2013, these jurisdictions, as well as the tax years that are no longer subject to examination, were as follows:

U.S. (federal) (a)	10/31/2010 and prior
Kentucky (state)	2010 and prior

(a) The ten month period ending October 31, 2010 remains open under the standard three year statute of limitations; however, the IRS has completed its audit of these periods under the Compliance Assurance Process, effectively closing them to audit adjustments. No issues remain outstanding.

4. Utility Rate Regulation

Regulatory Assets and Liabilities

As discussed in Note 1 and summarized below, LG&E reflects the effects of regulatory actions in the financial statements for its cost-based rate-regulated utility operations. Regulatory assets and liabilities are classified as current if, upon initial recognition, the entire amount related to that item will be recovered or refunded within a year of the balance sheet date.

LG&E is subject to the jurisdiction of the KPSC and FERC.

LG&E'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, LG&E 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. LG&E recovers in customer rates the cost of coal contracts, power purchases and emission allowances. As a result, management believes the regulatory assets and liabilities created to offset the fair value amounts at LKE’s acquisition date meet the recognition criteria established by existing accounting guidance and eliminate any rate-making impact of the fair value adjustments. LG&E's customer rates will continue to reflect the original contracted prices for these contracts.

The following tables provide information about the regulatory assets and liabilities of cost-based rate-regulated utility operations at December 31.

	2013	2012
Current Regulatory Assets:		
Environmental cost recovery	$ 2	$ 1
Gas supply clause	10	11
Fuel adjustment clause	2	6
Demand side management	3	1
Total current regulatory assets	$ 17	$ 19
Noncurrent Regulatory Assets:		
Defined benefit plans	$ 164	$ 232
Storm costs	51	59
Unamortized loss on debt	18	20
Interest rate swaps	44	67
AROs	21	15
Other	5	7
Total noncurrent regulatory assets	$ 303	$ 400
Current Regulatory Liabilities:		
Gas supply clause	$ 3	$ 4
Gas line tracker	6	-
Total current regulatory liabilities	$ 9	$ 4
Noncurrent Regulatory Liabilities:		
Coal contracts (a)	$ 43	$ 61
Power purchase agreement - OVEC (a)	69	75
Net deferred tax assets	26	28
Interest rate swaps	43	7
Other	2	3
Total noncurrent regulatory liabilities	$ 183	$ 174

(a) These liabilities were recorded as offsets to certain intangible assets that were recorded at fair value upon the acquisition of LKE.

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 the portion of unrecognized transition obligation, prior service cost and net actuarial losses that will be recovered in defined benefit plans expense through future base rates based upon established regulatory practices 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 re-measured. Of the regulatory asset and liability balances recorded, costs of $13 million are expected to be amortized into net periodic defined benefit costs in 2014.

Storm Costs

LG&E has the ability to request from the KPSC the authority to treat expenses related to specific extraordinary storms as a regulatory asset and defer and amortize such costs for regulatory accounting and reporting purposes. Once such authority is granted, LG&E can request recovery of those expenses in a base rate case.

Unamortized Loss on Debt

Unamortized loss on reacquired debt represents losses on long-term debt reacquired or redeemed that have been deferred and will be amortized and recovered over either the original life of the extinguished debt or the life of the replacement debt (in the case of refinancing). Such costs are being amortized through 2035.

Environmental Cost Recovery

Kentucky law permits LG&E to recover the costs, including a return of operating expenses and a return of and on capital invested, of complying with the Clean Air Act and those federal, state or local environmental requirements which apply to coal combustion wastes and by-products from coal-fired electric generating facilities. The KPSC requires reviews of the past operations of the environmental surcharge for six-month and two-year billing periods to evaluate the related charges, credits and rates of return, as well as to provide for the roll-in of ECR amounts to base rates each two-year period. The ECR regulatory asset or liability represents the amount that has been under- or over-recovered due to timing or adjustments to the mechanism and is typically recovered within 12 months. As a result of the settlement agreement in the 2012 rate case, beginning in 2013, LG&E will receive a 10.25% return on equity for all ECR projects included in the 2009 and 2011 compliance plans. In 2012, LG&E was authorized to receive a 10.63% return on equity for projects associated with the 2009 compliance plan and a 10.10% return on equity for projects associated with the 2011 compliance plan.

Gas Supply Clause

LG&E's natural gas rates contain a gas supply clause, whereby the expected cost of natural gas supply and variances between actual and expected costs from prior periods are adjusted quarterly in LG&E's rates, subject to approval by the KPSC. The gas supply clause includes a separate natural gas procurement incentive mechanism, which allows LG&E's rates to be adjusted annually to share variances between actual costs and market indices between the shareholders and the customers during each performance-based rate year (12 months ending October 31). The regulatory assets or liabilities represent the total amounts that have been under- or over-recovered due to timing or adjustments to the mechanisms and are typically recovered within 18 months.

Fuel Adjustment Clauses

LG&E'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 LG&E's rates. The KPSC requires public hearings at six-month intervals to examine past fuel adjustments and at two-year intervals to review past operations of the fuel 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.

Demand Side Management

LG&E's DSM programs consist of energy efficiency programs which are intended to reduce peak demand and delay the investment in additional power plant construction, provide customers with tools and information to become better managers of their energy usage and prepare for potential future legislation governing energy efficiency. LG&E's rates contain a DSM provision which includes a rate recovery mechanism that provides for concurrent recovery of DSM costs, and allows for the recovery of DSM revenues from lost sales associated with the DSM programs. Additionally, LG&E earns an approved return on equity for capital expenditures associated with the residential and commercial load management/demand conservation programs. The cost of DSM programs is assigned only to the class or classes of customers that benefit from the programs.

Interest Rate Swaps

In November 2012 and April 2013, LG&E entered into forward-starting interest rate swaps with PPL that hedged the interest payments on new debt that was expected to be issued in 2013. In September 2013, these hedges were terminated and LG&E entered into new forward-starting interest rate swaps with PPL, effectively extending the start date of the prior hedges from September 2013 to December 2013. All of these swaps had terms identical to forward-starting swaps entered into by PPL with third parties. New debt totaling $250 million was issued in November 2013 and the hedges issued in September were terminated in November 2013. Net cash settlements of $43 million were received on the swaps that were terminated in September and November, which are included in "Cash Flows from Operating Activities" on the Statements of Cash Flows. Net realized gains on these swaps will be returned through regulated rates. As such, the net settlements were reclassified from AOCI to regulatory liabilities and are being recognized in "Interest Expense" on the Statements of Income over the life of the newly issued debt. For the year ended December 31, 2013, there was no hedge ineffectiveness recorded for the interest rate derivatives. See Note 14 for additional information related to the forward-starting interest rate swaps.

In addition to the hedges terminated as a result of the debt issuance, realized amounts associated with LG&E's interest rate swaps, including a terminated swap contract from 2008, are recoverable through rates based on an order from the KPSC, LG&E's unrealized losses and gains are recorded as a regulatory asset or liability until they are realized as interest expense. Interest expense from existing swaps is realized and recovered over the terms of the associated debt, which matures through 2033. Amortization of the gain or loss related to the 2008 terminated swap contract is to be recovered through 2035, as approved by the KPSC.

AROs

As discussed in Note 1, the accretion and depreciation expenses related to LG&E's AROs are recorded as a regulatory asset, such that there is no earnings impact. When an asset with an ARO is retired, the related ARO regulatory asset is offset against the associated cost of removal regulatory liability, PP&E and ARO liability.

Gas Line Tracker

In the 2012 rate case order, the KPSC approved the GLT rate recovery mechanism. The GLT authorizes LG&E to recover its incremental operating expenses and depreciation, and to earn a 10.25% return on equity for capital associated with the five year gas service riser and leak mitigation program. As part of this program, LG&E makes necessary repairs and assumes ownership of natural gas lines. LG&E annually files projected costs in October to become effective on the first billing cycle in January. After the completion of a plan year, LG&E submits a balancing adjustment filing to the KPSC to amend rates charged for the differences between the actual costs and actual GLT charges for the preceding year.

Coal Contracts

As a result of purchase accounting associated with PPL's acquisition of LKE, LG&E's coal contracts were recorded at fair value on the Balance Sheets with offsets to regulatory assets for those contracts with unfavorable terms relative to current market prices and offsets to regulatory liabilities for those contracts with favorable terms relative to current market prices. These regulatory assets and liabilities are being amortized over the same terms as the related contracts, which expire at various times through 2016.

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 regulatory liabilities. The regulatory liabilities are being amortized using the units-of-production method until March 2026, the expiration date of the agreement at the date of the acquisition.

Regulatory Liability Associated with Net Deferred Tax Assets

LG&E's regulatory liabilities associated with net deferred tax assets represent the future revenue impact from the reversal of deferred income taxes required primarily for unamortized investment tax credits. These regulatory liabilities are recognized when the offsetting deferred tax assets are recognized. For general-purpose financial reporting, these regulatory liabilities and the deferred tax assets are not offset; rather, each is displayed separately.

Regulatory Matters

Rate Case Proceedings

In December 2012, the KPSC approved a rate case settlement agreement providing for increases in annual base electricity rates of $34 million and an increase in annual base gas rates of $15 million and authorized a 10.25% return on equity. The approved rates became effective January 1, 2013.

CPCN Filings

In January 2014, LG&E and KU filed an application for a CPCN with the KPSC requesting approval to build a NGCC generating unit at KU's Green River generating site and a solar generating facility at the E. W. Brown generating site.

Storm Costs

In August 2011, a strong storm hit LG&E's service area causing significant damage and widespread outages for approximately 139,000 customers. LG&E filed an application with the KPSC in September 2011, requesting approval of a regulatory asset recorded to defer, for future recovery, $8 million in incremental operation and maintenance expenses related to the storm restoration. An order was received in December 2011 granting the request. On December 20, 2012, the KPSC, in the approval of the unanimous rate case settlement agreement, authorized regulatory asset recovery effective January 1, 2013, over a five year period.

5. Financing Activities

Credit Arrangements and Short-term Debt

LG&E maintains a credit facility to enhance liquidity, provide credit support and provide a backup to its commercial paper program. The amounts borrowed below are recorded as “Short-term debt” on the Balance Sheets. The following credit facility was in place at:

	December 31, 2013				
	Expiration Date	Capacity	Borrowed	Letters of Credit Issued and Commercial Paper Backup	Unused Capacity
Syndicated Credit Facility (a) (b)	Nov. 2017	$ 500	-	$ 20	$ 480

	December 31, 2012	
	Borrowed	Letters of Credit Issued and Commercial Paper Backup
Syndicated Credit Facility (a) (b)	-	$ 55

(a) LG&E pays customary fees under its facility and borrowings generally bear interest at LIBOR-based rates plus an applicable margin.
(b) The facility contains a financial covenant requiring debt to total capitalization not to exceed 70% as calculated in accordance with the facility and other customary covenants.

LG&E 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 LG&E's Syndicated Credit Facility. The following commercial paper program was in place at:

December 31, 2013			
Weighted - Average Interest Rate	**Capacity**	**Commercial Paper Issuances**	**Unused Capacity**
0.29%	$ 350	$ 20	$ 330

December 31, 2012	
Weighted - Average Interest Rate	**Commercial Paper Issuances**
0.42%	$ 55

See Note 11 for discussion of intercompany borrowings.

Long-term Debt

	Weighted-Average Rate	**Maturities**	**December 31, 2013**
Senior Secured Notes/First Mortgage Bonds (a) (b)	2.77%	2015 - 2043	$ 1,359
Fair market value adjustments			(1)
Unamortized discount			(5)
Total Long-term Debt			$ 1,353

			December 31, 2012
Senior Secured Notes/First Mortgage Bonds (a) (b)	2.49%	2015 - 2040	$ 1,109
Fair market value adjustments			6
Unamortized discount			(3)
Total Long-term Debt			$ 1,112

(a) LG&E's first mortgage bonds are secured by the lien of the LG&E 2010 Mortgage Indenture which creates a lien, subject to certain exceptions and exclusions, on substantially all of LG&E's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity and the storage and distribution of natural gas. The aggregate carrying value of the property subject to the lien was $3.2 billion and $2.7 billion at December 31, 2013 and 2012.

(b) Includes LG&E's series of first mortgage bonds that were issued to the respective trustees of tax-exempt revenue bonds to secure its respective obligations to make payments with respect to each series of bonds. The first mortgage bonds were issued in the same principal amount, contain payment and redemption provisions that correspond to and bear the same interest rate as such tax-exempt revenue bonds. These first mortgage bonds were issued under the LG&E 2010 Mortgage Indenture and are secured as noted in (a) above. The related tax-exempt revenue bonds were issued by various governmental entities, principally counties in Kentucky, on behalf of LG&E. The related revenue bond documents allow LG&E to convert the interest rate mode on the bonds from time to time to a commercial paper rate, daily rate, weekly rate, term rate of at least one year or, in some cases, an auction rate or a LIBOR index rate.

At December 31, 2013, the aggregate tax-exempt revenue bonds issued on behalf of LG&E that were in a term rate mode totaled $294 million. At December 31, 2013, the aggregate tax-exempt revenue bonds issued on behalf of LG&E that were in a variable rate mode totaled $280 million.

Several series of the tax-exempt revenue bonds are insured by monoline bond insurers whose ratings were reduced due to exposures relating to insurance of sub-prime mortgages. Of the bonds outstanding, $135 million are in the form of insured auction rate securities, wherein interest rates are reset either weekly or every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. During 2008, interest rates increased, and LG&E experienced failed auctions when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture. As noted above, the instruments governing these auction rate bonds permit LG&E to convert the bonds to other interest rate modes.

Certain variable rate tax-exempt revenue bonds totaling $120 million at December 31, 2013, are subject to tender for purchase by LG&E at the option of the holder and to mandatory tender for purchase by LG&E upon the occurrence of certain events.

None of the outstanding debt securities noted above have sinking fund requirements. The aggregate maturities of long-term debt for the periods 2014 through 2018 and thereafter are $250 million in 2015 and $1,109 million after 2018.

Long-term Debt and Equity Securities Activities

In November 2013, LG&E issued $250 million of 4.65% First Mortgage Bonds due 2043. LG&E received proceeds of $246 million, net of discounts and underwriting fees, which were used for repayment of short-term debt, including commercial paper, for capital expenditures and for other general corporate purposes.

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NOTES TO FINANCIAL STATEMENTS (Continued)

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.

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 their 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 these subsidiaries may not satisfy their debts from the assets of LKE (or their 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, Capital Contributions and Related Restrictions

LG&E is subject to Section 305(a) of the Federal Power Act, which makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in capital account." The meaning of this limitation has never been clarified under the Federal Power Act. LG&E believes, however, that this statutory restriction, as applied to its circumstances, would not be construed or applied by the FERC to prohibit the payment from retained earnings of dividends that are not excessive and are for lawful and legitimate business purposes. In February 2012, LG&E 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, FERC approved the petition with the further condition that LG&E may not pay dividends if such payment would cause its adjusted equity ratio to fall below 30% of total capitalization. Accordingly, at December 31, 2013, net assets of $1.0 billion were restricted for purposes of paying dividends to LKE, and net assets of $1.0 billion were available for payment of dividends to LKE. LG&E believes it will not be required to change its current dividend practices as a result of the foregoing requirement. Orders from the KPSC require LG&E to obtain prior consent or approval before lending amounts to PPL.

During the year, LG&E paid dividends of $99 million to its parent, LKE, and received capital contributions of $86 million from LKE.

6. Acquisitions, Development and Divestitures

LG&E from time to time 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 the projects, sell, cancel or expand them, execute tolling agreements or pursue other options. Any resulting transactions may impact future financial results.

Development

Cane Run Unit 7 Construction

In September 2011, LG&E and KU filed an application for a CPCN with the KPSC requesting approval to build Cane Run Unit 7. In May 2012, the KPSC issued an order approving the request. LG&E will own a 22% undivided interest, and KU will own a 78% undivided interest in the new NGCC generating unit. A formal request for recovery of the costs associated with the construction was not included in the CPCN application but certain Cane Run Unit 7 construction work in progress has been included in base rates and the remaining capital costs are expected to be included in future rate proceedings. LG&E and KU commenced preliminary construction activities in the third quarter of 2012 and project construction is expected to be completed by May 2015. The project, which includes building a natural gas supply pipeline and related transmission projects, has an estimated cost of approximately $600 million.

In conjunction with this construction and to meet new, more stringent EPA regulations with a 2015 compliance date, LG&E anticipates retiring three older coal-fired electric generating units at the Cane Run plant, which have a combined summer capacity rating of 563 MW.

Future Capacity Needs

In January 2014, LG&E and KU filed an application for a CPCN with the KPSC requesting approval to construct a NGCC unit at KU's Green River generating site (Green River Unit 5) and a solar generating facility at the E. W. Brown generating site. Subject to finalizing details, regulatory applications, permitting and construction schedules, Green River Unit 5 is expected to have approximately 700 MW of capacity at an estimated cost of $700 million and is planned to be operational in 2018. Green River Unit 5 will be jointly owned by LG&E and KU, with LG&E owning a 40% undivided interest and KU owning a 60% undivided interest. The solar generating facility is expected to have approximately 10 MW of capacity at an estimated cost of $36 million and is planned to be operational in 2016. The solar generating facility will be jointly owned by LG&E and KU, with LG&E owning a 36% undivided interest and KU owning a 64% undivided interest.

7. Leases

LG&E has entered into various agreements for the lease of office space, vehicles, land, gas storage and other equipment.

Rent expense for operating leases was $7 million at December 31, 2013 and 2012.

Total future minimum rental payments for all operating leases are estimated to be:

2014	$	6
2015		5
2016		4
2017		2
2018		2
Thereafter		12
Total	$	31

8. Retirement and Postemployment Benefits

Defined Benefits

LG&E sponsors and participates in non-contributory defined benefit pension plans. These plans are applicable to the majority of LG&E employees. The plan LG&E participates in is sponsored by LKE. LG&E 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 is reasonable. LG&E's and LKE's defined benefit pension plans were closed to new salaried and bargaining unit employees hired after December 31, 2005. Employees hired after December 31, 2005 receive additional company contributions above the standard matching contributions to their savings plans. The 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 following table provides the components of net periodic defined benefit costs for LG&E's pension benefit plan for the years ended December 31.

	LG&E Sponsored Pension Benefits	
	2013	2012
Net periodic defined benefit costs (credits):		
Service cost	$ 2	$ 2
Interest cost	14	14
Expected return on plan assets	(20)	(19)
Amortization of:		
Prior service cost (credit)	2	3
Actuarial (gain) loss	14	11
Net periodic defined benefit costs (credits)	$ 12	$ 11
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets - Gross:		
Net (gain) loss	$ (20)	$ 18
Amortization of:		
Prior service cost	(2)	(2)
Actuarial (loss)	(14)	(11)
Total recognized in regulatory assets	(36)	5
Total recognized in net periodic benefit costs and regulatory assets	$ (24)	$ 16

For the plan sponsored by LG&E, the estimated amounts to be amortized from regulatory assets into net periodic defined benefit costs in 2014 are $8 million ($2 million amortization of prior service cost and $6 million amortization of actuarial loss). For the plan LG&E participates in, estimated amounts to be amortized from regulatory assets into net periodic defined benefit costs in 2014 are $5 million ($2 million amortization of prior service cost and $3 million amortization of actuarial loss).

The net periodic defined benefit costs charged to operating expense, excluding amounts charged to construction and other non-expense accounts, for LG&E’s pension benefits were $14 million and $13 million in 2013 and 2012. Allocations to LG&E for net periodic defined benefit costs charged to operating expense, excluding amounts charged to construction and other non-expense accounts, for pension benefits were $5 million in 2013 and 2012. Net periodic defined benefits costs charged to operating expense, excluding amounts charged to construction and other non-expense accounts for other postretirement benefits were $4 million and $5 million in 2013 and 2012. These allocated amounts are based on LG&E’s participation in those plans, which management believes is reasonable.

The following weighted-average assumptions were used in the valuation of the benefit obligations at December 31.

	LG&E Sponsored Pension Benefits	
	2013	**2012**
Discount rate	5.13%	4.20%

The following weighted-average assumptions were used to determine the net periodic defined benefit costs for the years ended December 31.

	LG&E Sponsored Pension Benefits	
	2013	**2012**
Discount rate	4.20%	5.00%
Expected return on plan assets (a)	7.10%	7.25%

(a) The expected long-term rates of return for pension benefits are based on management's projections using a best-estimate of expected returns, volatilities and correlations for each asset class. Each plan's specific current and expected asset allocations are also considered in developing a reasonable return assumption.

The funded status of LG&E's plan at December 31, was as follows:

	LG&E Sponsored Pension Benefits	
	2013	2012
Change in Benefit Obligation		
Benefit Obligation, beginning of period	$ 331	$ 298
Service cost	2	1
Interest cost	14	14
Actuarial (gain) loss	(35)	32
Gross benefits paid (a)	(21)	(14)
Benefit Obligation, end of period	$ 291	$ 331
Change in Plan Assets		
Plan assets at fair value, beginning of period	287	256
Actual return on plan assets	4	32
Employer contributions	11	13
Gross benefits paid (a)	(21)	(14)
Plan assets at fair value, end of period	281	287
Funded Status, end of period	$ (10)	$ (44)
Amounts recognized in the Balance Sheets consist of:		
Noncurrent liability	(10)	(44)
Net amount recognized, end of period	$ (10)	$ (44)

(a) LG&E's pension plan offered a limited-time program in 2013 during which terminated vested participants could elect to receive their accrued pension benefit as a one-time lump-sum payment. The increase in gross benefits paid is primarily the result of $7 million of lump-sum cash payments made to terminated vested participants in 2013 in connection with this offering.

LG&E's pension plan had projected and accumulated benefit obligations in excess of plan assets at December 31, 2013 and 2012.

In addition to the plan it sponsors, LG&E is allocated a portion of the funded status and costs of certain defined benefit plans sponsored by LKE based on its participation in those plans, which management believes are reasonable. The actuarially determined obligations of current active employees and retired employees are used as a basis to allocate total plan activity, including active and retiree costs and obligations. Allocations to LG&E for pension benefits resulted in a liability of $9 million and $58 million at December 31, 2013 and 2012.

Allocations to LG&E for other postretirement benefits resulted in a liability of $73 million and $81 million at December 31, 2013 and 2012.

Plan Assets - Pension Plans

The pension plans sponsored by LKE and LG&E are 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. The investment strategy for the Master Trust is to achieve a risk-adjusted return on a mix of assets that, in combination with the Company’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 on a plan basis based on input from external consultants with a goal of limiting funded status volatility. The EBPB monitors the investments in each portfolio on a plan basis, 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 on a plan basis, as well as the weighted average of such guidelines, as of the end of 2013 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	2013 Target Asset Allocation (a)	
	2013 (a)	Weighted Average	LKE Plans
Growth Portfolio	**59%**	**55%**	**55%**
Equity securities	30%		
Debt securities (b)	17%		
Alternative investments	12%		
Immunizing Portfolio	**39%**	**43%**	**43%**
Debt securities (b)	40%		
Derivatives	(1)%		
Liquidity Portfolio	**2%**	**2%**	**2%**
Total	100%	100%	100%

	Percentage of Trust Assets
	2012
Growth Portfolio	**58%**
Equity securities	31%
Debt securities (b)	18%
Alternative investments	9%
Immunizing Portfolio	**41%**
Debt securities (b)	34%
Derivatives	1%
Liquidity Portfolio	**1%**
Total	100%

(a) Allocations exclude consideration of a guaranteed annuity contract held by the LG&E and KU Retirement Plan.
(b) Includes commingled debt funds, which the Company treats as debt securities for asset allocation purposes.

LG&E's and LKE's pension plans' assets are invested solely in the PPL Services Corporation Master Trust, which is fully disclosed below. The fair value of LG&E's plan's assets of $281 million and $287 million at December 31, 2013 and 2012 represents an interest of approximately 7% in the Master Trust for both years. The fair value of LKE's plan's assets of $1.2 billion and $1.1 billion at December 31, 2013 and 2012 represent approximately 29% and 26% in the Master Trust.

The fair value of net assets in the pension plan trusts by asset class and level within the fair value hierarchy was:

	December 31, 2013			
	Total	**Level 1**	**Level 2**	**Level 3**
Cash and cash equivalents	$ 120	$ 120	$ -	$ -
Equity securities				
U.S.:				
Large-cap	480	134	346	-
Small-cap	137	137	-	-
Commingled debt	749	13	736	-
International	630	163	467	-
Debt securities:				
U.S. Treasury and U.S. government sponsored agency	617	563	54	-
Residential/commercial backed securities	12	-	11	1
Corporate	963	-	940	23
Other	24	-	24	-
International	7	-	7	-
Alternative investements				
Commodities	108	-	108	-
Real estate	134	-	134	-
Private equity	80	-	210	80
Hedge funds	210	-	-	-
Derivatives:				
Interest rate swaps and swapations	(49)	-	(49)	-
Other	12	-	12	-
Insurance contracts	37	-	-	37
PPL Services Corporation Master Trust assets, at fair value	$ 4,271	$ 1,130	$ 3,000	$ 141
Receivables and payables, net (a)	-	-	-	-
401(h) account restricted for other postretirement benefit obligations	(115)	-	-	-
Total PPL Services Corporation Master Trust pension assets	$ 4,156			

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NOTES TO FINANCIAL STATEMENTS (Continued)

	December 31, 2012			
	Total	**Level 1**	**Level 2**	**Level 3**
Cash and cash equivalents	$ 84	$ 84	$ -	$ -
Equity securities				
U.S.:				
Large-cap	558	206	352	-
Small-cap	124	124	-	-
Commingled debt	676	56	620	-
International	557	184	373	-
Debt securities:				
U.S. Treasury and U.S. government sponsored agency	704	634	70	-
Residential/commercial backed securities	12	-	11	1
Corporate	874	-	847	27
Other	24	-	23	1
International	7	-	7	-
Alternative investements				
Commodities	59	-	59	-
Real estate	93	-	93	-
Private equity	75	-	-	75
Hedge funds	125	-	125	-
Derivatives:				
Interest rate swaps and swapations	36	-	36	-
Other	2	-	2	-
Insurance contracts	42	-	-	42
PPL Services Corporation Master Trust assets,at fair value	$ 4,052	$ 1,288	$ 2,618	$ 146
Receivables and payables, net (a)	(11)	-	-	-
401(h) account restricted for other postretirement benefit obligations	(102)	-	-	-
Total PPL Services Corporation Master Trust pension assets	$ 3,939			

(a) Receivables and payables represent amounts for investments sold/purchased but not yet settled along with interest and dividends earned but not yet received.

A reconciliation of pension trust assets classified as Level 3 at December 31, 2013 is as follows:

	Residential/ commercial backed securities	**Corporate debt**	**Private equity**	**Insurance contracts**	**Other debt**	**Total**
Balance at beginning of period	$ 1	$ 27	$ 75	$ 42	$ 1	$ 146
Actual return on plan assets	-	-	-	-	-	-
Relating to assets still held at the reporting date	-	-	3	2	-	5
Relating to assets sold the period during	-	5	-	-	-	5
Purchases, sales and settlements	-	(9)	2	(7)	-	(14)
Transfers from level 2 to level 3	-	-	-	-	-	-
Transfers from level 3 to level 2	-	-	-	-	(1)	(1)
Balance at end of period	$ 1	$ 23	$ 80	$ 37	$ -	$ 141

A reconciliation of pension trust assets classified as Level 3 at December 31, 2012 is as follows:

	Residential/ commercial backed securities	**Corporate debt**	**Private equity**	**Insurance contracts**	**Other debt**	**Total**
Balance at beginning of period	$ -	$ 7	$ 45	$ 46	$ -	$ 98
Actual return on plan assets	-	-	-	-	-	-
Relating to assets still held at the reporting date	-	1	10	3	-	14
Relating to assets sold the period during	-	2	-	-	-	2
Purchases, sales and settlements	1	21	20	(7)	-	35
Transfers from level 2 to level 3	-	-	-	-	1	1
Transfers from level 3 to level 2	-	(4)	-	-	-	(4)
Balance at end of period	$ 1	$ 27	$ 75	$ 42	$ 1	$ 146

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. These investments are classified as Level 2, except for exchange-traded funds, which are classified as Level 1 based on quoted prices in active markets. The fair value measurements for Level 2 investments are based on firm quotes of net asset values per share, which are not considered obtained from a quoted price in an active market. 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 evaluated prices 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, reported trades, broker/dealer bid/ask prices, benchmark securities and credit valuation adjustments. When necessary, the fair value of debt securities is measured using the income approach, which incorporates similar observable inputs as well as monthly payment data, future predicted cash flows, collateral performance and new issue data. For the PPL Services Corporation 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; and exchange traded funds.

Investments in commodities represent ownership of units of a commingled fund that is invested as a long-only, unleveraged portfolio of exchange-traded futures and forward contracts in tangible commodities to obtain broad exposure to all principal groups in the global commodity markets, including energies, agriculture and metals (both precious and industrial) using proprietary commodity trading strategies. The fund has daily liquidity with a specified notification period. The fund's fair value is based upon a unit value as calculated by the fund's trustee.

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. Four of the partnerships have limited lives of ten years, while the fifth has a life of 15 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 PPL Services Corporation Master Trust has unfunded commitments of $76 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 three hedge fund of 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 all market conditions. Major investment strategies for the hedge fund of funds include long/short equity, market neutral, distressed debt, and relative value. Generally, shares may be redeemed with 65 to 95 days prior written notice. The funds are subject to short term lockups and have limitations on the amount that may be withdrawn based on a percentage of the total net asset value of the fund, among other restrictions. All withdrawals are subject to the general partner's approval. The fair value for two of the funds has been estimated using the net asset value per share and the third fund's fair value is based on an ownership interest in partners' capital to which a proportionate share of net assets is attributed.

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.

Plan Assets – Other Postretirement Benefit Plans

LKE’s postretirement benefit plan is invested primarily in a 401(h) account, with insignificant amounts invested in money market funds within VEBA trusts for liquidity. LKE’s other postretirement benefit plan was invested primarily in a 401(h) account as disclosed in the PPL Services Corporation Master Trusts.

Expected Cash Flows - Defined Benefit Plans

LG&E's defined benefit plan has the option to utilize available prior year credit balances to meet current and future contribution requirements. LG&E does not plan to contribute to its pension plan in 2014. LG&E contributed $8 million to LKE’s pension plan on behalf of LG&E employees in January 2014.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid by the plans for LG&E retirees.

	LG&E Sponsored Pension Plan	**Allocated from LKE Pension Plan**
2014	$ 15	$ 11
2015	15	11
2016	15	11
2017	16	12
2018	17	12
2019-2023	99	68

Savings Plans

Substantially all employees of LG&E are eligible to participate in a 401(k) deferred savings plan. Employer contributions to the plan were $7 million and $6 million in 2013 and 2012.

9. Jointly Owned Facilities

At December 31, 2013 and 2012, the Balance Sheets reflect the owned interests in the facilities listed below.

	Ownership Interest	Electric Plant	Accumulated Depreciation	Construction Work in Progress
December 31, 2013				
Generating Plants				
E.W. Brown Units 6-7	38.00%	$ 40	$ 7	$ 1
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00%	46	5	1
Trimble County Unit 1	75.00%	308	42	18
Trimble County Unit 2	14.25%	200	19	14
Trimble County Units 5-6	29.00%	29	3	-
Trimble County Units 7-10	37.00%	69	7	1
Cane Run Unit 7	22.00%	-	-	91
Green River Unit 5	40.00%	-	-	1
December 31, 2012				
Generating Plants				
E.W. Brown Units 6-7	38.00%	$ 40	$ 5	$ -
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00%	46	3	-
Trimble County Unit 1	75.00%	304	33	10
Trimble County Unit 2	14.25%	198	14	13
Trimble County Units 5-6	29.00%	29	2	-
Trimble County Units 7-10	37.00%	68	6	2
Cane Run Unit 7	22.00%	-	-	16

LG&E provides its own funding for its share of each of the above facilities. LG&E 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 Purchases, Energy Sales and Other Commitments

Energy Purchase Commitments

LG&E and KU enter into purchase contracts to supply the coal and natural gas requirements for generation facilities and LG&E's gas supply operations. These contracts include the following commitments:

Contract Type	Maximum Maturity Date
Coal	2019
Coal Transportation and Fleeting Services	2024
Natural Gas Storage	2024
Natural Gas Transportation	2024

LG&E 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. Future obligations for power purchases from OVEC are unconditional demand payments, comprised of annual minimum debt service payments, as well as contractually required reimbursement of plant operating, maintenance and other expenses as follows:

2014	$ 18
2015	18
2016	18
2017	19
2018	20
Thereafter	504
	$ 597

In addition, LG&E had total energy purchases under the OVEC power purchase agreement of $18 million and $20 million during 2013 and 2012.

Legal Matters

LG&E is involved in legal proceedings, claims and litigation in the ordinary course of business. LG&E cannot predict the outcome of such matters, or whether such matters may result in material liabilities, unless otherwise noted.

Regulatory Issues

See Note 4 for information on regulatory matters related to utility rate regulation.

Enactment of Financial Reform Legislation

The Dodd-Frank Act became effective in July 2010 and includes provisions that impose derivative transaction reporting requirements and require most over-the-counter derivative transactions to be executed through an exchange and to be centrally cleared. The Dodd-Frank Act also provides that the U.S. Commodity Futures Trading Commission (CFTC) may impose collateral and margin requirements for over-the-counter derivative transactions, as well as capital requirements for certain entity classifications. The CFTC is establishing final rules on major provisions in the Dodd-Frank Act through its rulemaking process. Several final rules providing for the definition of the terms "swap", "swap dealer", and "major swap participant" became effective in October 2012. The entity classification thresholds and requirements set forth in these final rules do not require LG&E to register as either a swap dealer or major swap participant. Consequently, as commercial end users, LG&E is not subject to the heightened regulatory requirements applicable to swap dealers or major swap participants, including Business Conduct Standards, enhanced recordkeeping and reporting, clearing and exchange trading of CFTC-mandated swaps and other complex requirements under other CFTC regulations. The Dodd-Frank Act and its implementing regulations, however, have imposed on LG&E significant additional and costly recordkeeping, reporting and documentation requirements.

LG&E could face significantly higher operating costs or may be required to post additional collateral if it or its counterparties are subject to capital or margin requirements as ultimately adopted in the implementing regulations of the Dodd-Frank Act. Additionally, the burden that the Dodd-Frank Act and implementing regulations impose on all market participants could cause decreased liquidity in the bilateral swap market as financial entities discontinue their proprietary trading operations. Decreased liquidity could increase costs for LG&E to successfully meet hedge targets. LG&E will continue to evaluate the provisions of the Dodd-Frank Act and its implementing regulations, but could incur significant costs related to compliance with the Act and regulations.

FERC Market-Based Rate Authority

In 1998, the FERC authorized LG&E and KU to make wholesale sales of electricity and related products at market-based rates. In that order, the FERC directed LG&E and KU to file an updated market analysis within three years after the order, and every three years thereafter. Since then, periodic market-based rate filings with the FERC have been made by LG&E and KU. In June 2011, FERC approved PPL’s market-based rate update for the Southeast region, including LG&E and KU. Also, in June 2011, the FERC issued an order approving LG&E's and KU’s request for a determination that they no longer be deemed to have market power in the BREC balancing area and removing restrictions on their market-based rate authority in such region. LG&E cannot predict the ultimate outcome of these update filings at this time.

Electricity - Reliability Standards

The NERC is responsible for establishing and enforcing mandatory reliability standards (Reliability Standards) regarding the bulk power system. The FERC oversees this process and independently enforces the Reliability Standards.

The Reliability Standards have the force and effect of law and apply to certain users of the bulk power electricity system, including electric utility companies, generators and marketers. Under the Federal Power Act, the FERC may assess civil penalties of up to $1 million per day, per violation, for certain violations.

LG&E monitors its compliance with the Reliability Standards and continues to self-report potential violations of certain applicable reliability requirements and submit accompanying mitigation plans, as required. The resolution of a number of potential violations is pending. Any Regional Reliability Entity (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 by LG&E, certain other instances of potential non-compliance may be identified from time to time. LG&E cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any, other than the amounts currently recorded.

In October 2012, the FERC initiated its consideration of proposed changes to Reliability Standards to address the impacts of Geomagnetic Disturbances on the reliable operation of the bulk-power system, which might, among other things, lead to a requirement to install equipment that blocks geo-magnetically induced currents on implicated transformers. On May 16, 2013, FERC issued Order No. 779, requiring NERC to submit two types of Reliability Standards for FERC's approval in twelve month intervals. The first type would require certain owners and operators of the nation's electricity infrastructure, such as LG&E, to develop and implement operational procedures to mitigate the effects of Geomagnetic Disturbances on the bulk-power system. This NERC proposed standard was filed by NERC with FERC for approval in January of 2014, with a comment due date of March 24, 2014. The second type is to require owners and operators of the bulk-power system to assess certain Geomagnetic Disturbance events and develop and implement plans to protect the bulk-power system from those events and must be filed by NERC with FERC for approval by January 22, 2015. LG&E may be required to make significant expenditures in new equipment or modifications to its facilities to comply with the new requirements. LG&E is unable to predict the amount of any expenditures that may be required as a result of the adoption of any Reliability Standards for Geomagnetic Disturbances.

Environmental Matters

Due to the environmental issues discussed below or other environmental matters, it may be necessary for LG&E 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 impact of these permits and rules.

LG&E 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 which are 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 for LG&E are subject to rate recovery before the KPSC. LG&E can provide no assurances as to the ultimate outcome of future environmental or rate proceedings before regulatory authorities.

Air

CSAPR (formerly Clean Air Transport Rule) and CAIR

In July 2011, the EPA adopted the CSAPR. The CSAPR replaced the EPA's previous CAIR which was invalidated in July 2008 by the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court). CAIR subsequently was effectively reinstated by the D.C. Circuit Court in December 2008, pending finalization of the CSAPR. Like CAIR, CSAPR targeted sources in the eastern U.S. and would have required reductions in sulfur dioxide and nitrogen oxides in two phases (2012 and 2014).

In December 2011, the D.C. Circuit Court stayed implementation of the CSAPR and left CAIR in effect pending a final decision on the validity of the rule. In August 2012, the D.C. Circuit Court issued a ruling invalidating CSAPR, remanding the rule to the EPA for further action, and leaving CAIR in place during the interim. In June 2013, the U.S. Supreme Court granted the EPA's petition for review of the D.C. Circuit Court's August 2012 decision. Oral arguments before the U.S. Supreme Court were held in December 2013. Prior to a revised transport rule from the EPA, coal-fired generating plants could face tighter emission limitations on nitrogen oxides through state action.

The Kentucky fossil-fueled generating plants can meet the CAIR sulfur dioxide emission requirements by utilizing sulfur dioxide allowances (including banked allowances and optimizing existing controls). To meet standards for nitrogen oxides under the CAIR, LG&E will need to buy allowances and/or make operational changes. LG&E does not currently anticipate that the costs of meeting these reinstated CAIR standards will be significant.

National Ambient Air Quality Standards

LG&E’s fossil-fueled generating plants may face further reductions in emissions as a result of more stringent national ambient air quality standards for ozone, nitrogen oxides, sulfur dioxide and/or fine particulates.

In 2010, the EPA finalized a new one-hour standard 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 part of Jefferson County in Kentucky. Attainment must be achieved by 2018. States are working on designations for other areas.

In December 2012, the EPA issued final rules that strengthen the fine particulate standards. Under the final rules, states and the EPA have until 2015 to identify non-attainment areas, and states have until 2020 to achieve attainment for those areas.

LG&E anticipates that some of the measures required for compliance with the CAIR, or the MATS, or the Regional Haze requirements (as discussed below), such as upgraded or new sulfur dioxide scrubbers at certain plants and the previously announced retirement of coal-fired generating units at the Cane Run plant, will help to achieve compliance with the new one-hour sulfur dioxide standard. If additional reductions were to be required, the financial impact could be significant.

Until particulate matter and sulfur dioxide maintenance and compliance plans are developed by the EPA and state or local agencies, including identification and finalization of attainment designations for particulate matter, LG&E cannot predict the impact of the new standards.

MATS

In May 2011, the EPA published a proposed regulation requiring stringent reductions of mercury and other hazardous air pollutants from power plants. In February 2012, the EPA published the final rule, known as the MATS, with an effective date of April 2012. The rule is being challenged by industry groups and states in the D.C. Circuit Court, where oral arguments were held in December 2013. The rule provides for a three-year compliance deadline with the potential for a one-year extension as provided under the statute. LG&E has received compliance extensions for certain plants. LG&E is considering extension requests for other plants as well.

At the time the MATS rule was proposed, LG&E filed requests with the KPSC for environmental cost recovery based on its expected need to install environmental controls including chemical additive and fabric-filter baghouses to remove air pollutants. Recovery of the cost of certain controls was granted by the KPSC in December 2011. LG&E's anticipated retirement of certain coal-fired electricity generating units located at Cane Run is in response to MATS and other environmental regulations. LG&E is continuing to assess whether any revisions of its approved compliance plans will be necessary.

LG&E is continuing to conduct in-depth reviews of the MATS, including the potential implications to scrubber wastewater discharges. See the discussion of effluent limitations guidelines and standards below.

Regional Haze and Visibility

The EPA's regional haze programs were developed under the Clean Air Act to eliminate man-made visibility degradation by 2064. Under the programs, states are required to take action via state plans to make reasonable progress every decade, including the application of Best Available Retrofit Technology (BART) on power plants commissioned between 1962 and 1977.

The primary power plant emissions affecting visibility are sulfur dioxide, nitrogen oxides and particulates. To date, the focus of regional haze activity has been the western U.S. because the EPA had determined that the regional trading program in the eastern U.S. under CSAPR satisfied BART requirements to reduce sulfur dioxide and nitrogen oxides. However, the D.C. Circuit Court's August 2012 decision to vacate and remand CSAPR and to implement CAIR in its place on an interim basis leaves power plants located in the eastern U.S., including LG&E’s plants, exposed to reductions in sulfur dioxide and nitrogen oxides as required by BART, unless the D.C. Circuit Court's decision, now pending before the U.S. Supreme Court, is overturned.

In addition to this exposure stemming from the remand of CSAPR, LG&E's Mill Creek Units 3 and 4 are required to reduce sulfuric acid mist emissions because they were determined to have a significant regional haze impact. These reductions are in the Kentucky Division of Air Quality's regional haze state implementation plan that was submitted to the EPA. LG&E is currently installing sorbent injection technology to comply with these reductions, the costs of which are not expected to be significant.

New Source Review (NSR)

The EPA has continued its NSR enforcement efforts targeting coal-fired generating plants. The EPA has asserted that modification of these plants has increased their emissions and, consequently, that they are subject to stringent NSR requirements under the Clean Air Act.

In August 2007, LG&E received information requests for the Mill Creek and Trimble County plants, but has received no further communications from the EPA since providing its responses. LG&E cannot predict the outcome of these matters, and cannot estimate a range of reasonably possible losses, if any.

States and environmental groups also have commenced litigation alleging violations of the NSR regulations by coal-fired generating plants across the nation. If LG&E is found to have violated NSR regulations by significantly increasing pollutants through a major plant modification, it would, among other things, be required to meet stringent permit limits reflecting Best Available Control Technology (BACT) for pollutants meeting the National Ambient Air Quality Standards (NAAQS) in the area and reflecting Lowest Achievable Emission Rates (LAER) for pollutants not meeting the NAAQS in the area. The costs to meet such limits, including installation of technology at certain units, could be significant.

TC2 Air Permit

The Sierra Club and other environmental groups petitioned the Kentucky Environmental and Public Protection Cabinet to overturn the air permit issued for the TC2 baseload generating unit, but the agency upheld the permit in an order issued in September 2007. In response to subsequent petitions by environmental groups, the EPA ordered certain non-material changes to the permit which, in January 2010, were incorporated into a final revised permit issued by the KDAQ. In March 2010, the environmental groups petitioned the EPA to object to the revised state permit. Until the EPA issues a final ruling on the pending petition and all available appeals are exhausted, LG&E cannot predict the outcome of this matter or the potential impact on the capital costs of this project, if any.

Cane Run Environmental Claims

In the 2011 to 2013 time period, the Louisville Metro Air Pollution Control District issued several notices of violation alleging violations of local air quality rules at the Cane Run plant. In November 2013, LG&E entered into a settlement resolving the pending citations in return for payment of a civil penalty in a non-material amount and performance of remedial measures not expected to result in material costs.

On September 6, 2013, LG&E received a letter on behalf of two residents adjacent to the Cane Run plant notifying various federal, state, and local agencies of their intent to file a citizen suit for alleged violations of the Clean Air Act (CAA) and Resource Conservation and Recovery Act (RCRA). On December 16, 2013, six residents, on behalf of themselves and others similarly situated, filed a class action complaint against LG&E in the U.S. District Court for the Western District of Kentucky for alleged violations of the CAA and RCRA. In addition, these plaintiffs assert common law claims of nuisance, trespass, and negligence. These plaintiffs seek injunctive relief and civil penalties that would accrue to governmental agencies, plus costs and attorney fees, for the alleged statutory violations. Under the common law claims, these plaintiffs seek monetary compensation and punitive damages for property damage and diminished property values for a class consisting of residents within four miles of the plant. In their individual capacities, these plaintiffs seek compensation for alleged adverse health effects. LG&E cannot predict the outcome of this matter or the potential impact on operations of the Cane Run plant. LG&E has previously announced that it anticipates retiring the coal-fired units at Cane Run before the end of 2015.

GHG Regulations and Tort Litigation

As a result of the April 2007 U.S. Supreme Court decision that the EPA has authority under the Clean Air Act to regulate GHG emissions from new motor vehicles, in April 2010, the EPA and the U.S. Department of Transportation issued new light-duty vehicle emissions standards that applied beginning with 2012 model year vehicles. The EPA also clarified that this standard, beginning in 2011, authorized regulation of GHG emissions from stationary sources under the NSR and Title V operating permit provisions of the Clean Air Act. As a result, any new sources or major modifications to existing GHG sources causing a net significant emissions increase now require adherence to the BACT permit limits for GHGs. The rules were challenged, and in June 2012 the D.C. Circuit Court upheld the EPA's regulations. In December 2012, the D.C. Circuit Court denied petitions for rehearing pertaining to its June 2012 opinion. On October 15, 2013, the U.S. Supreme Court granted certiorari for several petitions to decide whether the NSR provisions of the Clean Air Act require the EPA to regulate GHG emissions from stationary sources, such as power plants.

In June 2013, President Obama released his Climate Action Plan which reiterates the goal of reducing greenhouse gas emissions in the U.S. "in the range of" 17% below 2005 levels by 2020 through such actions as regulating power plant emissions, promoting increased use of renewables and clean energy technology, and establishing tighter energy efficiency standards. Also, by Presidential Memorandum the EPA was directed to issue a revised proposal for new power plants (a prior proposal was issued in 2012) by September 20, 2013, with a final rule in a timely fashion thereafter, and to issue proposed standards for existing plants by June 1, 2014 with a final rule to be issued by June 1, 2015. The EPA was further directed to require that states develop implementation plans for existing plants by June 2016. Regulation of existing plants could have a significant industry-wide impact depending on the structure and stringency of the final rule and the state implementation plans. The Administration's recent increase in its estimate of the "social cost of carbon" (which is used to calculate benefits associated with proposed regulations) from $23.80 to $38 per metric ton in 2015 may also lead to more costly regulatory requirements; the White House Office of Management and Budget (OMB) has opened this issue for public comment. Additionally, the Climate Action Plan requirements related to preparing the U.S. for the impacts of climate change could affect LG&E and others in the industry as modifications to electricity delivery systems to improve the ability to withstand major storms may be needed in order to meet those requirements.

The EPA issued its revised proposal for new sources on September 20, 2013 as directed by the White House. This proposal was published in the Federal Register on January 8, 2014, with comments due on March 10, 2014. Unlike the EPA's prior proposal, the EPA's revised proposal established separate emission standards for coal and gas units based on the application of different technologies. The coal standard is based on the application of partial carbon capture and sequestration technology, but because this technology is not presently commercially available, the revised proposal effectively precludes the construction of new coal plants. The EPA proposed the same standard for NGCC power plants as was proposed in 2012 and may not be consistently achievable. In addition, the EPA deleted the explicit exemption previously proposed for simple-cycle natural gas plants.

In November 2008, the Governor of Kentucky issued a comprehensive energy plan including non-binding targets aimed at promoting improved energy efficiency, development of alternative energy, development of carbon capture and sequestration projects, and other actions to reduce GHG emissions. In December 2009, the Kentucky Climate Action Plan Council was established to develop an action plan addressing potential GHG reductions and related measures. In November 2011, the Council issued a final report to the Secretary of Kentucky's Energy and Environment Cabinet for his consideration. The final report acknowledged that the recommendations would require additional review and analysis prior to implementation, and that many of the recommendations would likely require, in part, further legislative or regulatory actions. The impact of any such plan is not now determinable, but the costs to comply with the plan could be significant.

A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting plants and, although the decided cases to date have not sustained claims brought on the basis of these theories of liability, the law remains unsettled on these claims. In September 2009, the U.S. Court of Appeals for the Second Circuit in the case of AEP v. Connecticut reversed a federal district court's decision and ruled that several states and public interest groups, as well as the City of New York, could sue five electric utility companies under federal common law for allegedly causing a public nuisance as a result of their emissions of GHGs. In June 2011, the U.S. Supreme Court overturned the Second Circuit and held that such federal common law claims were displaced by the Clean Air Act and regulatory actions of the EPA. In addition, in Comer v. Murphy Oil (Comer case), the U.S. Court of Appeals for the Fifth Circuit (Fifth Circuit) declined to overturn a district court ruling that plaintiffs did not have standing to pursue state common law claims against companies that emit GHGs. The complaint in the Comer case named the previous indirect parent of LKE as a defendant based upon emissions from the Kentucky plants. In January 2011, the Supreme Court denied a petition to reverse the Fifth Circuit's ruling. In May 2011, the plaintiffs in the Comer case filed a substantially similar complaint in federal district court in Mississippi against 87 companies, including four of LG&E’s affiliates but excluding LG&E, under a Mississippi statute that allows the re-filing of an action in certain circumstances. In March 2012, the Mississippi federal district court granted defendants' motions to dismiss the state common law claims. Plaintiffs appealed to the U.S. Court of Appeals for the Fifth Circuit, and in May 2013, the Fifth Circuit affirmed the district court's dismissal of the case. Additional litigation in federal and state courts over such issues is continuing. LG&E cannot predict the outcome of these lawsuits or estimate a range of reasonably possible losses, if any.

In 2013, LG&E and its jointly owned power plants emitted approximately 17 million tons of carbon dioxide compared with 18 million tons in 2012. All tons are U.S. short tons (2,000 pounds/ton).

Renewable Energy Legislation

There has been interest in renewable energy legislation at both the state and federal levels. Federal legislation on renewable energy is not expected to be enacted this year.

LG&E believes there are financial, regulatory and logistical uncertainties related to the implementation of renewable energy mandates that will need to be resolved before the impact of such requirements on them can be estimated. Such uncertainties, among others, include the need to provide back-up supply to augment intermittent renewable generation, potential generation over-supply and downward pressure on energy prices that could result from such renewable generation and back-up, impacts to PJM's capacity market and the need for substantial changes to transmission and distribution systems to accommodate renewable energy sources. These uncertainties are not directly addressed by proposed legislation. LG&E cannot predict at this time the effect of renewable energy mandates that may be adopted, although the costs to implement and comply with any such requirements could be significant.

Water/Waste

Coal Combustion Residuals (CCRs)

In June 2010, the EPA proposed two approaches to regulating the disposal and management of CCRs (as either hazardous or non-hazardous) under the Resource Conservation and Recovery Act (RCRA). CCRs include fly ash, bottom ash and sulfur dioxide scrubber wastes. Regulating CCRs as a hazardous waste under Subtitle C of the RCRA would materially increase costs and result in early retirements of many coal-fired plants, as it would require plants to retrofit their operations to comply with full hazardous waste requirements for the generation of CCRs and associated waste waters through generation, transportation and disposal. This would also have a negative impact on the beneficial use of CCRs and could eliminate existing markets for CCRs. The EPA's proposed approach to regulate CCRs as non-hazardous waste under Subtitle D of the RCRA would mainly affect disposal and most significantly affect any wet disposal operations. Under this approach, many of the current markets for beneficial uses would not be affected. Currently, LG&E expects that several of its plants could be significantly impacted by the EPA's proposed non-hazardous waste regulations, as these plants are using surface impoundments for management and disposal of CCRs.

The EPA has issued information requests on CCR management practices at numerous plants throughout the power industry as it considers whether or not to regulate CCRs as hazardous waste. LG&E has provided information on CCR management practices at most of its plants in response to the EPA's requests. In addition, the EPA has conducted follow-up inspections to evaluate the structural stability of CCR management facilities at several plants and has implemented or is implementing certain actions in response to recommendations from these inspections.

The EPA is continuing to evaluate the unprecedented number of comments it received on its June 2010 proposed regulations. In October 2011, the EPA issued a Notice of Data Availability (NODA) requesting comments on selected documents it received during the comment period for the proposed regulations. In September 2013, in response to the proposed Effluent Limitation Guidelines, PPL submitted comments on the proposed CCR regulations. Also, in September 2013, PPL commented on a second CCR NODA seeking comment on additional information related to the EPA's proposal.

A coalition of environmental groups and two CCR recycling companies have filed lawsuits against the EPA seeking a deadline for final rulemaking and, in settlement of that litigation, the EPA has agreed to issue its final rulemaking by the end of 2014.

In July 2013, the U.S. House of Representatives passed House Bill H.R. 2218, the Coal Residuals and Reuse Management Act of 2013, which would preempt the EPA from issuing final CCR regulations and would set non-hazardous CCR standards under RCRA and authorize state permit programs. It remains uncertain whether similar legislation will likely be passed by the U.S. Senate. LG&E cannot predict at this time the final requirements of the EPA's CCR regulations or potential changes to the RCRA and what impact they would have on its facilities, but the financial and operational impact is expected to be material if CCRs are regulated as hazardous waste and significant if regulated as non-hazardous.

Trimble County Landfill Permit

In May 2011, LG&E submitted an application for a special waste landfill permit to handle coal combustion residuals generated at the Trimble County plant. After extensive review of the permit application in May 2013, the Kentucky Division of Waste Management denied the permit application on the grounds that the proposed facility would violate the Kentucky Cave Protection Act because it would eliminate an on-site karst feature considered to be a cave. After assessing additional options for managing coal combustion residuals, in January 2014, LG&E submitted to the Kentucky Division of Waste Management a landfill permit application for an alternate site adjacent to the plant. LG&E and KU are unable to determine the precise impact of this matter until a landfill permit is issued and any resulting legal challenges are concluded.

Seepages and Groundwater Infiltration

Seepages or groundwater infiltration has been detected at active and retired wastewater basins and landfills at various LG&E plants. LG&E has completed or is completing assessments of seepages or groundwater infiltration at various facilities and has completed or is working with agencies to implement assessment or abatement measures, where required. A range of reasonably possible losses cannot currently be estimated.

Clean Water Act 316(b)

The EPA published proposed rule 316(b) for existing facilities in April 2011. The EPA has been evaluating the comments it received to the proposed rule and meeting with industry groups to discuss options. The proposed rule contains two requirements to reduce impact to aquatic organisms at cooling water intake structures. The first requires all existing facilities to meet standards for the reduction of mortality of aquatic organisms that become trapped against water intake screens (impingement) regardless of the levels of mortality actually occurring or the cost to achieve the standards. The second requirement is to determine and install the best technology available to reduce mortality of aquatic organisms pulled through a plant's cooling water system (entrainment). A form of cost-benefit analysis is allowed for this second requirement involving a site-specific evaluation based on nine factors, including impacts to energy delivery reliability and the remaining useful life of the plant. The final rule is expected by April 17, 2014. Until the final rule is issued, LG&E cannot estimate a range of reasonably possible costs, if any, that would be required to comply with such a regulation.

Effluent Limitations Guidelines (ELGs) and Standards

In June 2013, the EPA published proposed regulations to revise discharge limitations for steam electric generation wastewater permits. The proposed limitations are based on the EPA review of available treatment technologies and their capacity for reducing pollutants and include new requirements for fly ash and bottom ash transport water and metal cleaning waste waters, as well as new limits for scrubber wastewater and landfill leachate. The EPA's proposed ELG regulations contain requirements that would affect the inspection and operation of CCR facilities, if finalized. The EPA has indicated that it will coordinate these regulations with the regulation of CCRs discussed above. The proposal contains alternative approaches, some of which could significantly impact LG&E’s coal-fired plants. LG&E worked with industry groups to comment on the proposed regulation on September 20, 2013. The final regulation is expected to be issued in May 2014 but it may be delayed. At the present time, LG&E is unable to predict the outcome of this matter or estimate a range of reasonably possible costs, but the costs could be significant. Pending finalization of the ELGs, certain states and environmental groups (including Kentucky) are proposing more stringent technology-based limits in permit renewals. Depending on the final limits imposed, the costs of compliance could be significant and costs could be imposed ahead of federal timelines.

Other Issues

The EPA is reassessing its polychlorinated biphenyls (PCB) regulations under the Toxic Substance Control Act, which currently allow certain PCB articles to remain in use. In April 2010, the EPA issued an Advanced Notice of Proposed Rulemaking for changes to these regulations. This rulemaking could lead to a phase-out of all or some PCB-containing equipment. The EPA is planning to propose the revised regulations in November 2014. PCBs are found, in varying degrees, in LG&E’s operations. LG&E cannot predict at this time the outcome of these proposed EPA regulations and what impact, if any, they would have on its facilities, but the costs could be significant.

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County plant. In November 2010, the Cabinet issued a final order upholding the permit. In December 2010, the environmental groups appealed the order to the Trimble Circuit Court, but the case was subsequently transferred to the Franklin Circuit Court. In September 2013, the court reversed the Cabinet order upholding the permit and remanded the permit to the agency for further proceedings. In October 2013, LG&E filed a notice of appeal with the Kentucky Court of Appeals. LG&E is unable to predict the outcome of this matter or estimate a range of reasonably possible losses, if any.

The EPA and the Army Corps of Engineers are working on a guidance document that will expand the federal government's interpretation of what constitutes "waters of the U.S." subject to regulation under the Clean Water Act. This change has the potential to affect generation and delivery operations, with the most significant effect being the potential elimination of the existing regulatory exemption for plant waste water treatment systems. The costs that may be imposed on LG&E as a result of any eventual expansion of this interpretation cannot reliably be estimated at this time but could be significant.

Superfund and Other Remediation

LG&E is remediating or has completed the remediation of several sites that were not addressed under a regulatory program such as Superfund, but for which LG&E may be liable for remediation. These include a number of former coal gas manufacturing plants previously owned or operated or currently owned by predecessors or affiliates of LG&E. There are additional sites, formerly owned or operated by LG&E

predecessors or affiliates, for which LG&E lacks information on current site conditions and is therefore unable to predict what, if any, potential liability they may have.

Depending on the outcome of investigations at sites where investigations have not begun or been completed or developments at sites for which LG&E currently lacks information, the costs of remediation and other liabilities could be material. LG&E cannot estimate a range of reasonably possible losses, if any, related to these matters.

The EPA is evaluating the risks associated with polycyclic aromatic hydrocarbons and naphthalene, chemical by-products of coal gas manufacturing. As a result of the EPA's evaluation, individual states may establish stricter standards for water quality and soil cleanup. This could require LG&E to take more extensive assessment and remedial actions at former coal gas manufacturing plants. LG&E cannot estimate a range of reasonably possible losses, if any, related to these matters.

From time to time, LG&E undertakes remedial action in response to spills or other releases at various on-site and off-site locations, negotiates with the EPA and state and local agencies regarding actions necessary for compliance with applicable requirements, negotiates with property owners and other third parties alleging impacts from LG&E’s operations and undertakes similar actions necessary to resolve environmental matters which arise in the course of normal operations. Based on analyses to date, resolution of these environmental matters is not expected to have a significant adverse impact on LG&E’s operations.

Future cleanup or remediation work at sites currently under review, or at sites not currently identified, may result in significant additional costs for LG&E.

Other

Labor Unions

In 2014, certain labor agreement negotiations are scheduled to begin. For LG&E, negotiations with the IBEW will begin in October 2014. The current agreement expires in November 2014. LG&E cannot predict the outcome of the union labor negotiations.

The labor agreement expiring in 2014 covered 701 employees at December 31, 2013, which is 70% of LG&E’s total workforce.

Guarantees and Other Assurances

In the normal course of business, LG&E 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 the creditworthiness attributed to a subsidiary on a stand-alone basis or to facilitate the commercial activities in which these subsidiaries engage.

Pursuant to the OVEC power purchase contract, LG&E 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 currently included within a demand charge designed to cover these costs over the term of the contract. LG&E's proportionate share of OVEC's outstanding debt was $89 million at December 31, 2013. The maximum exposure and the expiration date of these potential obligations are not presently determinable. See "Energy Purchases Commitments" above for additional information on the OVEC power purchase contract.

LG&E provides other miscellaneous guarantees through contracts entered into in the normal course of business. These guarantees are primarily in the form of indemnification or warranties related to services or equipment and vary in duration. The amounts of these guarantees often are not explicitly stated, and the overall maximum amount of the obligation under such guarantees cannot be reasonably estimated. Historically, no significant payments have been made with respect to these types of guarantees and the probability of payment/performance under these guarantees is remote.

PPL, on behalf of itself and certain of its subsidiaries including LG&E, 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

LG&E and KU jointly dispatch their generation units with the lowest cost generation used to serve their retail customers. When LG&E has excess generation capacity after serving its own retail customers and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail customers and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are reflected in the Statements of Income as "Electric revenue from affiliate" and "Energy purchases from affiliate" and are recorded at a price equal to the seller's fuel cost. Savings realized from such intercompany transactions are shared equally between 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 LG&E with administrative, management and support services. Where applicable, the costs of these services are charged to LG&E as direct support costs. General costs that cannot be directly attributed to LG&E are allocated and charged as indirect support costs. LKS bases its indirect allocations on LG&E’s number of employees, total assets, revenues, number of customers and/or other statistical information. LKS charged the following amounts for the years ended December 31, and believe these amounts are reasonable, including amounts applied to accounts that are further distributed between capital and expense.

2013	2012
$ 216	$ 186

LG&E and KU also provide services to each other and to LKS. Billings between LG&E and KU relate to labor and overheads associated with union and hourly employees performing work for the other company, charges related to jointly-owned generating units and other miscellaneous charges. Tax settlements between LKE and LG&E are reimbursed through LKS.

Intercompany Derivatives

Periodically, LG&E 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. See Note 14 for additional information on intercompany derivatives.

Other

See Note 1 for discussions regarding the intercompany tax sharing agreement and Note 5 for a discussion regarding capital transactions by LG&E. See Note 8 for discussions regarding intercompany allocations associated with defined benefits.

12. Other Income (Expense) – net

The components of "Other Income (Expense) - net" for 2013 and 2012 for LG&E were not significant.

13. Fair Value Measurements and Credit Concentration

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). 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 2013 and 2012, 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, 2013			
	Total	Level 1	Level 2	Level 3
Assets				
Cash and cash equivalents	$ 8	$ 8	$ -	$ -
Restricted cash and cash equivalents (a)	22	22	-	-
Total assets	$ 30	$ 30	$ -	$ -
Liabilities				
Price risk management liabilities:				
Interest rate swaps	$ 36	$ -	$ 36	$ -
Total liabilities	$ 36	$ -	$ 36	$ -

	December 31, 2012			
	Total	Level 1	Level 2	Level 3
Assets				
Cash and cash equivalents	$ 22	$ 22	$ -	$ -
Restricted cash and cash equivalents (a)	32	32	-	-
Price risk management assets:				
Interest rate swaps	7	-	7	-
Total assets	$ 61	$ 54	$ 7	$ -
Liabilities				
Price risk management liabilities:				
Interest rate swaps	$ 58	$ -	$ 58	$ -
Total liabilities	$ 58	$ -	$ 58	$ -

(a) Included in "Other noncurrent assets" on the Balance Sheets.

Price Risk Management Assets/Liabilities - Interest Rate Swaps

To manage interest rate risk, LG&E 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) 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. Accounting personnel, who report to the CFO, interpret analysis quarterly to classify the contracts in the fair value hierarchy. Valuation techniques are evaluated periodically.

Financial Instruments Not Recorded at Fair Value

The carrying amounts of long-term debt on the Balance Sheets and its 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 the credit risk of LG&E. These instruments are classified as Level 2. The effect of third-party credit enhancements is not included in the fair value measurement.

	December 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 1,353	$ 1,372	$ 1,112	$ 1,178

The carrying value of short-term debt (including notes between affiliates), when outstanding, approximates fair value due to the variable interest rates associated with the short-term debt and is classified as Level 2.

Credit Concentration Associated with Financial Instruments

Contracts are entered into with many entities for the purchase and sale of energy. When NPNS is elected, the fair value of these contracts is not reflected in the financial statements. However, the fair value of these contracts is considered when committing to new business from a credit perspective. See Note 14 for information on credit policies used to manage credit risk, including master netting arrangements and collateral requirements.

At December 31, 2013, LG&E's credit exposure was not significant.

14. Derivative Instruments and Hedging Activities

Risk Management Objectives

PPL has a risk management policy approved by the Board of Directors to manage market risk (including price, liquidity and volumetric risk) and credit risk (including non-performance risk and payment default risk). Senior 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 and market prices, and verification of risk and transaction limits.

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 the contracts meet the definition of a derivative. All derivatives are recognized on the Balance Sheets at their fair value, unless NPNS is elected. The table below summarizes the market risks that affect LG&E.

Commodity price risk (including basis and volumetric risk)	M
Interest rate risk:	
Debt issuances	M
Defined benefit plans	M
Equity securities price risk:	
Defined benefit plans	M

M = The regulatory environment, by definition, significantly mitigates market risk.

Commodity price risk

LG&E's rates include certain mechanisms for fuel, gas supply and environmental expenses. These mechanisms generally provide for timely recovery of market price and volumetric fluctuations associated with these expenses.

Interest rate risk

LG&E is exposed to interest rate risk associated with forecasted fixed-rate and existing floating-rate debt issuances. LG&E utilizes over-the-counter interest rate swaps to limit exposure to market fluctuations on floating-rate debt and utilizes forward starting interest rate swaps to hedge changes in benchmark interest rates in connection with future debt issuances.

Credit Risk

Credit risk is the potential loss that may be incurred due to a counterparty's non-performance.

LG&E is exposed to credit risk from interest rate derivatives with third-party financial institutions.

The majority of LG&E’s credit risk stems from energy sales and purchases. In the event a supplier of LG&E defaults on its obligation, it would be required to seek replacement power or replacement fuel in the market. In general, incremental costs incurred by LG&E would be recoverable from customers in future rates, thus mitigating the financial risk for these entities.

LG&E 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. LG&E 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.

Master Netting Arrangements

Net derivative positions on the balance sheets are not offset against the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

LG&E had no obligation to return cash collateral under master netting arrangements at December 31, 2013 and 2012.

LG&E had posted cash collateral under master netting arrangements of $22 million and $32 million at December 31, 2013 and 2012.

See "Offsetting Derivative Investments" below for a summary of derivative positions presented in the balance sheets where a right of setoff exists under these arrangements.

Interest Rate Risk

LG&E issues debt to finance its operations, which exposes it to interest rate risk. Various financial derivative instruments are utilized to adjust the mix of fixed and floating interest rates in its debt portfolio, adjust the duration of the debt portfolio and lock in benchmark interest rates in anticipation of future financing, when appropriate. Risk limits under the risk management program are designed to balance risk exposure to volatility in interest expense and changes in the fair value of the debt portfolio due to changes in benchmark interest rates.

Cash Flow Hedges

In November 2012 and April 2013, LG&E entered into forward-starting interest rate swaps with PPL that hedged the interest payments on new debt that was expected to be issued in 2013. In September 2013, these hedges were terminated and LG&E entered into new forward-starting interest rate swaps with PPL, effectively extending the start date of the prior hedges from September 2013 to December 2013. All of these swaps had terms identical to forward-starting swaps entered into by PPL with third parties. New debt totaling $250 million was issued in November 2013 and the hedges issued in September were terminated in November 2013. Net cash settlements of $43 million were received on the swaps that were terminated in September and November, which are included in "Cash Flows from Operating Activities" on the Statement of Cash Flows. Realized gains and losses on these swaps are probable of recovery through regulated rates; as such, the net settlements were reclassified from AOCI to regulatory liabilities and are being recognized in "Interest Expense" on the Statements of Income over the life of the newly issued debt. For 2013, there was no hedge ineffectiveness recorded for the interest rate derivatives.

Economic Activity

LG&E enters into interest rate swap contracts that economically hedge interest payments on variable rate debt. Because realized gains and losses from the swaps, including a terminated swap contract, are recoverable through regulated rates, any subsequent changes in fair value of these derivatives are included in regulatory assets or liabilities until they are realized as interest expense. Realized gains and losses are recognized in "Interest Expense" on the Statements of Income when the hedged transaction occurs. At December 31, 2013, LG&E held contracts with a notional amount of $179 million that range in maturity through 2033.

Accounting and Reporting

All derivative instruments are recorded at fair value on the Balance Sheets as an asset or liability unless NPNS is elected. Changes in the fair value of derivatives not designated as NPNS are recognized currently in earnings unless specific hedge accounting criteria are met and designated as such, except for the change in fair value of LG&E's interest rate swaps that are recognized as regulatory assets or regulatory liabilities. See Note 4 for amounts recorded in regulatory assets and regulatory liabilities at December 31, 2013 and 2012.

See Note 1 for additional information on accounting policies related to derivative instruments.

The following table presents the fair value and the location on the Balance Sheets of derivative instruments designated as cash flow hedges.

	December 31, 2013		December 31, 2012	
	Assets	Liabilities	Assets	Liabilities
Current:				
Price Risk Management Assets/Liabilities (a):				
Interest rate swaps	$ -	$ -	$ 7	$ -

(a) Represents the location on the Balance Sheets.

The following table presents the pre-tax effect of derivative instruments designated as cash flow hedges that are recognized in regulatory liabilities.

Derivative Instruments	Location of Gain (Loss)	2013	2012
Interest rate swaps	Regulatory liabilities - noncurrent	$ 36	$ 7

The following table presents the fair value and the location on the Balance Sheets of derivatives not designated as hedging instruments.

	December 31, 2013		December 31, 2012	
	Assets	**Liabilities**	**Assets**	**Liabilities**
Current:				
Other Current Assets/Liabilities (a):				
Interest rate swaps	$ -	$ 4	$ -	$ 5
Total current	-	4	-	5
Noncurrent:				
Price Risk Management Assets/Liabilities (a):				
Interest rate swaps	-	32	-	53
Total noncurrent	-	32	-	53
Total derivatives	$ -	$ 36	$ -	$ 58

(a) Represents the location on the Balance Sheets.

The following tables present the pre-tax effect of derivatives not designated as cash flow hedges that are recognized in income or regulatory assets.

Derivative Instruments	**Location of Gain (Loss)**	**2013**	**2012**
Interest rate swaps	Interest Expense	$ (8)	$ (8)
Commodity contracts	Operating Revenues	-	-
	Total	$ (8)	$ (8)

Derivative Instruments	**Location of Gain (Loss)**	**2013**	**2012**
Interest rate swaps	Regulatory assets - noncurrent	$ 22	$ 1

Offsetting Derivative Instruments

LG&E has master netting arrangements or similar agreements in place including derivative clearing agreements with futures commission merchants (FCMs) to permit the trading of cleared derivative products on one or more futures exchanges. The clearing arrangements permit an FCM to use and apply any property in its possession as a set off to pay amounts or discharge obligations owed by a customer upon default of the customer and typically do not place any restrictions on the FCM's use of collateral posted by the customer. LG&E also enters into agreements pursuant to which it trades 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 setoff 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.

LG&E 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. The tables below summarize the derivative positions presented in the balance sheets where a right of setoff exists under these arrangements and related cash collateral received or pledged.

	Assets			
		Eligible for Offset		
	Gross	Derivative Instruments	Cash Collateral Received	Net
December 31, 2012				
Treasury derivatives	$ 7	$ -	$ -	$ 7

	Liabilities			
		Eligible for Offset		
	Gross	Derivative Instruments	Cash Collateral Received	Net
December 31, 2013				
Treasury derivatives	$ 36	$ -	$ 20	$ 16
December 31, 2012				
Treasury derivatives	$ 58	$ -	$ 30	$ 28

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 the credit ratings of LG&E. 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 the credit rating at levels that remain above investment grade. In either case, if the applicable credit rating were to fall below investment grade (i.e., below BBB- for S&P or Fitch, or Baa3 for Moody's), and assuming no assignment to an investment grade affiliate were allowed, most of these credit contingent 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.

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 the performance of LG&E's obligation under the contract. A counterparty demanding adequate assurance could require a transfer of additional collateral or other security, including letters of credit, cash and guarantees from a creditworthy entity. This would typically involve negotiations among the parties. However, amounts disclosed below represent assumed immediate payment or immediate and ongoing full collateralization for derivative instruments in net liability positions with "adequate assurance" features.

At December 31, 2013, the effect of a decrease in credit ratings below investment grade on derivative contracts that contain credit risk-related contingent features and were in a net liability position is summarized as follows:

Aggregate fair value of derivative instruments in a net liability position with credit risk-related contingent provisions	$	26
Aggregate fair value of collateral posted on these derivative instruments		22
Aggregate fair value of additional collateral requirements in the event of a credit downgrade below investment grade (a)		6

(a) Includes the effect of net receivables and payables already recorded on the Balance Sheets.

15. Other Intangible Assets

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2013		December 31, 2012	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Coal contracts (a)	$ 124	$ 81	$ 124	$ 62
Land and transmission rights	7	1	8	1
Emission allowances (b)	1	-	1	-
OVEC power purchase agreement (c)	87	17	87	13
Total subject to amortization	$ 219	$ 99	$ 220	$ 76

(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 is being amortized over the same period as the intangible assets, eliminating any income statement impact. See Note 4 for additional information.

(b) Represents the fair value at the acquisition date of emission allowances recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability is recorded related to these emission allowances, which is being amortized as the emission allowances are consumed, eliminating any income statement impact. Consumption related to these emission allowances was insignificant in 2013 and in 2012.

(c) 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. See Note 4 for additional information.

Current intangible assets are included in "Other current assets" on the Balance Sheets. Long-term intangible assets are presented as "Other intangibles" on the Balance Sheets.

Amortization expense, excluding consumption of emission allowances, was as follows:

	2013	2012
Intangible assets with regulatory offset	23	23
Total	$ 23	$ 23

Amortization expense for each of the next five years, excluding consumption of emission allowances, is estimated to be:

	2014	2015	2016	2017	2018
Intangibles with regulatory offset	$ 23	$ 24	$ 13	$ 6	$ 6

16. Asset Retirement Obligations

LG&E's AROs are primarily related to the final retirement of assets associated with generating units. LG&E also has AROs related to natural gas mains and wells. LG&E's transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, no material AROs are recorded for transmission and distribution assets. As described in Notes 1 and 4, LG&E's accretion and depreciation expense are recorded as a regulatory asset, such that there is no earnings impact. In 2013, AROs were revalued primarily due to updates in the estimated cash flows for ash ponds and CCR surface impoundments based on updated cost estimates.

The changes in the carrying amounts of AROs were as follows.

	2013	2012
ARO at beginning of period	$ 62	$ 57
Accretion expense	3	3
Changes in estimated cash flow or settlement date	17	5
Obligations settled	(8)	(3)
ARO at end of period	74	62

Substantially all of the ARO balances are classified as noncurrent at December 31, 2013 and 2012.

17. New Accounting Guidance Pending Adoption

Accounting for Obligations Resulting from Joint and Several Liability Arrangements

Effective January 1, 2014, LG&E will retrospectively adopt accounting guidance for the recognition, measurement and disclosure of certain obligations resulting from joint and several liability arrangements when the amount of the obligation is fixed at the reporting date. If the obligation is determined to be in the scope of this guidance, it will be measured as the sum of the amount the reporting entity agreed to pay on the basis of its arrangements among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. This guidance also requires additional disclosures for these obligations.

The adoption of this guidance is not expected to have a significant impact on LG&E.

Presentation of Unrecognized Tax Benefits When Net Operating Loss Carryforwards, Similar Tax Losses, or Tax Credit Carryforwards Exist

Effective January 1, 2014, LG&E will prospectively adopt accounting guidance that requires an unrecognized tax benefit, or a portion of an unrecognized tax benefit, to be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward. To the extent a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, or the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose, the unrecognized tax benefit should be presented in the financial statements as a liability and should not be combined with deferred tax assets.

The adoption of this guidance is not expected to have a significant impact on LG&E.

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18. Notes to Statement of Cash Flows

Supplemental disclosures of cash flow information.

	December 31, 2013	December 31, 2012
Cash paid during the period for:		
Income taxes	$ 51	$ 5
Interest on borrowed money	28	29
Other cash paid for interest	8	9

19. Notes to Statement of Income for the Year

See page 115, line 6, column (g). Electric Utility Depreciation Expense includes $8 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 6, column (i). Gas Utility Depreciation Expense includes $3 million applicable to Common Utility Plant apportioned to Gas Operations.

See page 115, line 8, column (g). Electric Utility Amortization and Depletion of Utility Plant includes $6 million applicable to Common Utility Plant apportioned to Electric Operations.

See page 115, line 8, column (i). Gas Utility Amortization and Depletion of Utility Plant includes $2 million applicable to Common Utility Plant apportioned to Gas Operations.

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(l)
Sponsoring Witness: Kent W. Blake

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 LG&E's shareholders during the period referenced. LG&E does not publish a statistical supplement.

Federal securities rules generally require the delivery of annual reports to public shareholders when requesting their vote via certain proxy solicitations. During the period in question, the common stock of LG&E has been wholly-owned by LG&E and KU Energy LLC, which is a wholly-owned subsidiary of PPL Corporation.

Copies of the audited annual financial statements and other financial information of LG&E relating to the period described are provided in Filing Requirement 807 KAR 5:001 Section 16(7)(p) [Tab No. 46].

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(m)
Sponsoring Witness: Valerie L. Scott

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.

Account Number	Account Description
101101	PROPERTY UNDER CAPITAL LEASES
101102	PLANT IN SERVICE - ELECTRIC FRANCHISES AND CONSENTS
101103	PLANT IN SERVICE - MISC. INTANGIBLE PLANT
101104	PLANT IN SERVICE - ELECTRIC LAND
101105	PLANT IN SERVICE - ELECTRIC STRUCTURES
101106	PLANT IN SERVICE - ELECTRIC EQUIPMENT
101107	PLANT IN SERVICE - ELECTRIC ARO ASSET RETIREMENT COST-EQUIPMENT
101108	PLANT IN SERVICE - ELECTRIC HYDRO EQUIPMENT
101109	PLANT IN SERVICE - ELECTRIC DISTRIBUTION EQUIPMENT
101110	PLANT IN SERVICE - LEASED PROPERTY
101111	PLANT IN SERVICE - ELECTRIC GENERAL EQUIPMENT
101112	PLANT IN SERVICE - ELECTRIC COMMUNICATION EQUIPMENT
101113	PLANT IN SERVICE - ELECTRIC LAND RIGHTS
101125	PLANT IN SERVICE - ELECTRIC ARO ASSET RETIREMENT COST-LAND/BUILDING
101202	PLANT IN SERVICE - GAS FRANCHISES AND CONSENTS
101204	PLANT IN SERVICE - GAS LAND
101205	PLANT IN SERVICE - GAS STRUCTURES
101206	PLANT IN SERVICE - GAS UNDERGROUND AND TRANSMISSION EQUIPMENT
101207	PLANT IN SERVICE - GAS ARO ASSET RETIREMENT COST-EQUIPMENT
101208	PLANT IN SERVICE - GAS TRANSPORTATION EQUIPMENT
101209	PLANT IN SERVICE - GAS DISTRIBUTION EQUIPMENT
101211	PLANT IN SERVICE - GAS GENERAL EQUIPMENT
101213	PLANT IN SERVICE - GAS LAND RIGHTS
101225	PLANT IN SERVICE - GAS ARO ASSET RETIREMENT COST-LAND/BUILDING
101301	PLANT IN SERVICE - COMMON ORGANIZATION
101302	PLANT IN SERVICE - COMMON FRANCHISES AND CONSENTS
101303	PLANT IN SERVICE - COMMON MISC. INTANGIBLE PLANT
101304	PLANT IN SERVICE - COMMON LAND
101305	PLANT IN SERVICE - COMMON STRUCTURES
101311	PLANT IN SERVICE - COMMON GENERAL EQUIPMENT
101312	PLANT IN SERVICE - COMMON COMMUNICATION EQUIPMENT
101313	PLANT IN SERVICE - COMMON LAND RIGHTS
101315	PLANT IN SERVICE - COMMON GENERAL EQUIPMENT
101325	PLANT IN SERVICE - COMMON ARO ASSET RETIREMENT COST-LAND/BUILDING
102001	ELECTRIC PLANT-PURCHASED OR SOLD
105001	PLT HELD FOR FUT USE
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
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
108104	ACCUM. DEPR. - ELECTRIC LAND RIGHTS
108105	ACCUM. DEPR. - ELECTRIC STRUCTURES
108106	ACCUM. DEPR. - ELECTRIC EQUIPMENT
108107	ACCUM. DEPR. - ELECTRIC ARO ASSET RETIREMENT COST-EQUIPMENT
108108	ACCUM. DEPR. - ELECTRIC HYDRO EQUIPMENT
108109	ACCUM. DEPR. - ELECTRIC DISTRIBUTION EQUIPMENT
108110	ACCUM. DEPR. - LEASED PROPERTY
108111	ACCUM. DEPR. - ELECTRIC GENERAL EQUIPMENT
108112	ACCUM. DEPR. - ELECTRIC COMMUNICATION EQUIP.
108113	ACCUM. DEPR. - ELECTRIC TRANSPORTATION EQUIP.
108114	ACCUM. DEPR. - COR - ELECTRIC LAND RIGHTS
108115	ACCUM. DEPR. - COR - ELECTRIC STRUCTURES
108116	ACCUM. DEPR. - COR - ELECTRIC EQUIPMENT
108118	ACCUM. DEPR. - COR - ELECTRIC HYDRO EQUIPMENT
108119	ACCUM. DEPR. - COR - ELECTRIC DISTRIBUTION
108120	ACCUM. DEPR. - COR - ELECTRIC GENERAL PROPERTY
108121	ACCUM. DEPR. - COR - ELECTRIC COMMUNICATION EQUIP.
108122	ACCUM. DEPR. - COR - LEASED PROPERTY
108125	ACCUM. DEPR. - ELECTRIC ARO ASSET RETIREMENT COST-LAND/BUILDING
108204	ACCUM. DEPR. - GAS LAND RIGHTS
108205	ACCUM. DEPR. - GAS STRUCTURES
108206	ACCUM. DEPR. - GAS UNDERGROUND & TRANSMISSION EQUIPMENT
108207	ACCUM. DEPR. - GAS ARO ASSET RETIREMENT COST-EQUIPMENT
108209	ACCUM. DEPR. - GAS DISTRIBUTION EQUIPMENT
108211	ACCUM. DEPR. - GAS GENERAL EQUIP.
108213	ACCUM. DEPR. - GAS TRANSPORTATION EQUIP.

Account Number	Account Description
108215	ACCUM. DEPR. - COR - GAS STRUCTURES
108216	ACCUM. DEPR. - COR - GAS UNDERGROUND & TRANSMISSION EQUIP.
108219	ACCUM. DEPR. - COR - GAS DISTRIBUTION EQUIPMENT
108220	ACCUM. DEPR. - COR - GAS GENERAL EQUIP.
108225	ACCUM. DEPR. - GAS ARO ASSET RETIREMENT COST-LAND/BUILDING
108304	ACCUM. DEPR. - COMMON LAND RIGHTS
108305	ACCUM. DEPR. - COMMON STRUCTURES
108311	ACCUM. DEPR. - COMMON GENERAL EQUIPMENT
108312	ACCUM. DEPR. - COMMON COMMUNICATION EQUIPMENT
108313	ACCUM. DEPR. - COMMON TRANSPORTATION EQUIP.
108314	ACCUM. DEPR. - COMMON GENERAL EQUIPMENT - NONUTILITY
108315	ACCUM. DEPR. - COR - COMMON STRUCTURES
108321	ACCUM. DEPR. - COR - COMMON EQUIPMENT
108325	ACCUM. DEPR. - COMMON ARO ASSET RETIREMENT COST-LAND/BUILDING
108414	ACCUM. DEPR. - SALVAGE - ELECTRIC LAND RIGHTS
108415	ACCUM. DEPR. - SALVAGE - ELECTRIC STRUCTURES
108416	ACCUM. DEPR. - SALVAGE - ELECTRIC EQUIPMENT
108418	ACCUM. DEPR. - SALVAGE - ELECTRIC HYDRO EQUIPMENT
108419	ACCUM. DEPR. - SALVAGE - ELECTRIC DISTRIBUTION
108420	ACCUM. DEPR. - SALVAGE - ELECTRIC GENERAL PROPERTY
108421	ACCUM. DEPR. - SALVAGE - ELECTRIC COMMUNICATION EQUIP.
108515	ACCUM. DEPR. - SALVAGE - GAS STRUCTURES
108516	ACCUM. DEPR. - SALVAGE - GAS UNDERGROUND & TRANSMISSION EQUIP.
108519	ACCUM. DEPR. - SALVAGE - GAS DISTRIBUTION EQUIPMENT
108520	ACCUM. DEPR. - SALVAGE - GAS GENERAL EQUIP.
108621	ACCUM. DEPR. - SALVAGE - COMMON EQUIPMENT
108622	ACCUM. DEPR. - SALVAGE - COMMON COMMUNICATION EQUIPMENT
108799	RWIP-ARO LEGAL
108901	RETIREMENT - RWIP
111102	AMORTIZATION EXPENSE - ELECTRIC FRANCHISES AND CONSENTS
111103	AMORTIZATION EXPENSE - ELECTRIC INTANGIBLES
111202	AMORTIZATION EXPENSE - GAS FRANCHISES AND CONSENTS
111302	AMORTIZATION EXPENSE - COMMON FRANCHISES AND CONSENTS
111303	AMORTIZATION EXPENSE - COMMON INTANGIBLES
117001	GAS STORED-NONCUR
117101	GAS STORED - NONCURRENT RECOVERABLE BASE GAS
121001	NONUTIL PROP IN SERV
121007	PLANT IN SERVICE - ELECTRIC ARO ASSET RETIREMENT COST-EQUIPMENT
121103	MACHINERY & EQUIPMENT
121105	LEASEHOLD IMPROVEMENTS
121106	COMPUTER EQUIPMENT
121107	FURNITURE & FIXTURES
121108	COMPUTER SOFTWARE
122001	ACCUM DEPR/DEPL
122002	ACCUM AMORT-NONUTIL
122007	ACCUM. DEPR. - ELECTRIC ARO ASSET RETIRMENT COST-EQUIPMENT
122203	MACHINERY & EQUIPMENT - ACCUM DEPRECIATION
122205	LEASEHOLD IMPROVEMENTS - ACCUM DEPRECIATION
122206	COMPUTER EQUIPMENT - ACCUM DEPRECIATION
122207	FURNITURE & FIXTURES - ACCUM DEPRECIATION
122208	COMPUTER SOFTWARE - ACCUM DEPRECIATION
123102	INVESTMENT IN LGE PA ADJS
123103	INVEST IN LGE
123104	INVEST IN LGE CAPITAL
123105	INVESTMENT IN KU
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
123126	INVEST IN HOME SERVICES PA ADJS
123127	INVEST IN SERVCO PA ADJS
123128	INVEST IN WKE PA ADJS
123129	INVEST IN FCD LLC PA ADJS
123130	INVEST IN LEM PA ADJS
123133	INVEST IN DOWNTOWN COMMERICAL LOAD FUND
123134	INVESTMENT IN SUBS - CURRENT-YEAR EQUITY IN EARNINGS
123175	INVESTMENT IN KU PA ADJS
128023	PREPAID PENSION
128026	COLLATERAL DEPOSIT - IR SWAPS
128027	RESTRICTED CASH - NON-CURRENT
131024	CASH- BNY MELLON BANK
131033	US BANK - LGE - LOUISVILLE
131050	SUNDRY CASH COLLECT
131069	CASH CLEARING - CCS
131080	CASH LOCKBOX - BANK OF AMERICA - LOUISVILLE
131090	CASH-BOA A/P - CLEARING
131091	CASH-BOA PAYROLL
131092	CASH-BOA FUNDING
131093	CASH AT BANK - ARMORED CAR CREDIT
131203	US BANK - DANVILLE
131204	BANK OF AMERICA - REGULUS - KU
131205	FIRST SOUTHERN NATIONAL BANK - BARLOW
131206	US BANK - ELIZABETHTOWN

Account Number	Account Description
131207	FIRST UNITED BANK OF HOPKINS COUNTY - EARLINGTON
131208	BB&T - KU - EDDYVILLE
131209	FIRST NATIONAL BANK - GREENVILLE
131210	FIFTH THIRD BANK - MORGANFIELD
131211	US BANK - GEORGETOWN
131212	US BANK - WINCHESTER
131213	US BANK - RICHMOND
131214	CITIZENS BANK & TRUST CO - CAMPBELLSVILLE
131215	US BANK - SHELBYVILLE
131216	US BANK - MT. STERLING
131217	US BANK - LEXINGTON
131218	US BANK - MAYSVILLE
131221	US BANK - VERSAILLES
131223	CITIZENS BANK - MOREHEAD
131224	KENTUCKY BANK - PARIS
131226	US BANK - CARROLLTON
131227	US BANK - MASTER ROLL UP ACCOUNT
131229	CUMBERLAND VALLEY NATIONAL - LONDON
131230	FIRST STATE BANK - MIDDLESBORO
131231	BANK OF HARLAN - HARLAN
131232	CITIZENS NATIONAL BANK - SOMERSET
131233	FIRST BANK & TRUST - NORTON
131234	LEE BANK AND TRUST CO - PENNINGTON GAP
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
134007	RESTRICTED CASH - SHORT TERM
135001	WORKING FUNDS
136005	TEMP INV-OTHER
136015	TEMP INV-MONEY POOL-GOLDMAN SACHS <3 MOS
136016	TEMP INV-GOLDMAN SACHS-CASH UNRESTRICTED
136018	TEMP INV-FIDELITY INVESTMENTS-CASH UNRESTRICTED
136019	TEMP INV-JPMORGAN-CASH UNRESTRICTED
136020	TEMP INV-UBS-CASH UNRESTRICTED
141004	NOTES RECEIVABLE - INDUSTRIAL AUTHORITY
141005	RESERVE FOR NOTES RECEIVABLE - INDUSTRIAL AUTHORITY
142001	CUST A/R-ACTIVE
142002	A/R - UNPOSTEC CASH
142003	WHOLESALE SALES A/R
142004	TRANSMISSION RECEIVABLE
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)
143022	ACCTS REC - BEYOND THE METER
143024	A/R MUTUAL AID
143027	INCOME TAX RECEIVABLE - FEDERAL
143028	INCOME TAX RECEIVABLE - STATE
143030	EMPLOYEE PAYROLL ADVANCES
143032	ACCTS REC - TAX REFUNDS
143033	DEFAULT EMPLOYEE RECEIVABLES
143035	A/R - EUSIC/EON
143036	SUSPENSE - PPL
143037	STATE INCOME TAX RECEIVABLE
143040	ACCTS REC - WKE UNWIND - DISPATCH, IT ADHOC, & CENTURY
143041	COBRA/LTD BENEFITS - RECEIVABLE
143052	ACCOUNTS RECEIVABLE - IMEA/IMPA OFFSET

Account Number	Account Description
143053	BECHTEL RECEIVABLE LIQUIDATED
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 - BECHTEL RESERVE
144016	UNCOLL A/R - CENTURY INTEREST
145006	NOTES RECEIVABLE FROM LEM
145011	N/R - MONEY POOL - LGE
145012	N/R - MONEY POOL - KU
145013	N/R - MONEY POOL - LCC
145015	N/R - MONEY POOL - LEM
145020	NOTES RECEIVABLE FROM LKE - CURRENT
145021	NOTES RECEIVABLE - PPL ENERGY FUNDING - CURRENT
145022	N/R - MONEY POOL - FCD
145023	N/R - MONEY POOL - WKE
145025	NOTES RECEIVABLE FROM LG&E AND KU ENERGY LLC NON-CURRENT
145026	NOTES RECEIVABLE FROM LEM-NON CURRENT
145100	N/R MONEY POOL - LG&E AND KU ENERGY LLC
146048	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	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
146100	INTERCOMPANY
151010	FUEL STK-LEASED CARS
151020	COAL PURCHASES - TONS - $
151021	COAL - BTU ADJ - BTU
151022	COAL FINES - CONSIGNED INVENTORY
151023	IN-TRANSIT COAL - TONS - $
151024	COAL - CONSIGNED INVENTORY
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 - $
151070	PETROL COKE-TEM STOR - TONS
151071	PETROL COKE-TEM STOR - BTU
151073	IN-TRANSIT COAL-MMBTU/IN-TRANSIT PET COKE <AUG 2009
151080	COAL BARGE SHUTTLING
154001	MATERIALS/SUPPLIES
154003	LIMESTONE
154004	COMMERCIAL LIME
154006	OTHER REAGENTS
154007	TC NON-JURISDICTIONAL CONTRA (IMEA/IMPA) - LIMESTONE
154008	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - M&S
154023	LIMESTONE IN-TRANSIT
158121	SO2 ALLOWANCE INVENTORY
158122	NOX OZONE SEASON ALLOWANCE INVENTORY
158124	SO2 ALLOWANCE INVENTORY-FUTURE VINTAGE (LT)
158125	NOX ANNUAL ALLOWANCE INVENTORY
158126	NOX OZONE SEASON ALLOWANCE INVENTORY - FUTURE VINTAGE (LT)
158127	NOX ANNUAL ALLOWANCE INVENTORY - FUTURE VINTAGE (LT)
163001	STORES EXPENSE-T&D
163002	WAREHOUSE EXPENSES-T&D
163003	FREIGHT-T&D
163004	ASSET RECOVERY-T&D
163005	SALES TAX-T&D
163006	PHYS INVENT ADJUSTMT-T&D
163007	INVOICE PRICE VARIANCES-T&D
163011	STORES EXPENSE - GENERATION
163012	WAREHOUSE EXPENSES - GENERATION
163013	FREIGHT - GENERATION
163014	ASSET RECOVERY - GENERATION
163015	SALES TAX - GENERATION
163016	PHYS INVENT ADJUSTMT - GENERATION
163017	INVOICE PRICE VARIANCES - GENERATION
163100	OTHER-T&D
163101	OTHER - GENERATION
163201	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - STORES
164101	GAS STORED-CURRENT
165001	PREPAID INSURANCE
165002	PREPAID TAXES
165006	PREPAID GAS FRANCH
165012	PREPAID LEASE

Account Number	Account Description
165013	PREPAID RIGHTS OF WAY
165018	PREPAID RISK MGMT AND WC
165025	PREPAID SALES & USE TAX
165100	PREPAID OTHER
165101	PREPAID IT CONTRACTS
165102	TC NON-JURISDICTIONAL CONTRA (IMEA-IMPA) - PREPAID INSURANCE
171001	INTEREST RECEIVABLE
171003	DIVIDENDS RECEIVABLE-EXTERNAL
172001	RENTS RECEIVABLE FOR POLE ATTACHMENTS
173001	ACCRUED UTIL REVENUE
173002	ACCRUED REVENUE - UNBILLED BEYOND THE METER
173005	ACCRUED WHOLESALE SALES REVENUE - UNBILLED
174001	MISC CURR/ACCR ASSET
176003	ST DERIV ASSET FAS133 HEDGING - NON-LKE AFFILIATE
176004	LT DERIV ASSET FAS133 HEDGING - NON-LKE AFFILIATE
181100	UAMORTIZED DEBT EXPENSE
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	FERC JURISDICTIONAL PENSION EXPENSE
182314	OTHER REGULATORY ASSETS
182315	REGULATORY ASSET - FAS 158 PENSION
182317	OTHER REGULATORY ASSETS ARO - GENERATION
182318	OTHER REG ASSETS ARO - TRANSMISSION
182320	WINTER STORM - ELECTRIC
182321	MISO EXIT FEE
182322	RATE CASE EXPENSES - ELECTRIC - PRE-PPL MERGER CURRENT PORTION
182323	RATE CASE EXPENSES - GAS - PRE-PPL MERGER CURRENT PORTION
182325	OTHER REGULATORY ASSETS ARO - DISTRIBUTION
182326	OTHER REGULATORY ASSETS ARO - GAS
182327	OTHER REGULATORY ASSETS ARO - COMMON
182328	FASB 109 ADJ-FED
182329	FASB 109 GR-UP-FED
182330	FASB 109 ADJ-STATE
182331	FASB 109 GR-UP-STATE
182332	CMRG FUNDING (CARBON MGT RESEARCH GROUP)
182333	KCCS FUNDING (KY CONSORTIUM FOR CARBON STORAGE)
182334	WIND STORM REGULATORY ASSET
182335	RATE CASE EXPENSES - ELECTRIC
182336	RATE CASE EXPENSES - GAS
182337	EKPC FERC TRANSMISSION COSTS - KY PORTION
182339	MOUNTAIN STORM - ELECTRIC
182340	REG ASSET - PERFORMANCE-BASED RATES
182342	WINTER STORM - GAS
182343	ASSET - SWAP TERMINATION - PRE-PPL MERGER CURRENT PORTION
182344	REG ASSET - LT - SWAP TERMINATION
182345	WINTER STORM - ELECTRIC - PRE-PPL MERGER CURRENT PORTION
182346	WINTER STORM - GAS - PRE-PPL MERGER CURRENT PORTION
182347	WIND STORM - ELECTRIC - PRE-PPL MERGER CURRENT PORTION
182348	CMRG FUNDING - PRE-PPL MERGER CURRENT PORTION
182349	KCCS FUNDING - PRE-PPL MERGER CURRENT PORTION
182352	REG ASSET - LT INTEREST RATE SWAP
182353	REG. ASSET - COAL CONTRACT - ST
182354	REG. ASSET - COAL CONTRACT
182356	VA FUEL COMPONENT - JURISDICTIONAL CUSTOMERS (NON-CURRENT)
182358	REG ASSET - UNAMORT DEBT EXP PAA
182359	GENERAL MANAGEMENT AUDIT - ELECTRIC
182360	GENERAL MANAGEMENT AUDIT - GAS
182361	2011 SUMMER STORM - ELECTRIC
182363	DSM COST RECOVERY - UNDER-RECOVERY
182364	REG ASSET - LT INTEREST RATE SWAP FORWARD STARTING
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)
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	PENSIONS - BURDEN CLEARING
184097	FASB 106 (OPEB) - BURDEN CLEARING
184098	FASB 112 (OPEB) - BURDEN CLEARING
184100	WALL STREET SUSPENSE ACCOUNT
184101	GROUP LIFE INSURANCE - BURDEN CLEARING
184104	DENTAL INSURANCE - BURDEN CLEARING
184105	MEDICAL INSURANCE - BURDEN CLEARING
184108	401K - BURDEN CLEARING

Account Number	Account Description
184109	RETIREMENT INCOME - BURDEN CLEARING
184121	OTHER BENEFITS - BURDEN CLEARING
184130	LKS ALLOCATION CLEARING ACCOUNT
184135	ORACLE PROJECT BURDEN CLEARING ACCOUNT
184136	LKS ALLOC. CLEARING ACCOUNT FOR ALLOCATED CAPITAL
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
184530	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
184650	CUSTOMER ADVANCES - CLEARING
184701	EMPLOYEE ADVANCES - CLEARING
184702	IEXPENSE CREDIT CARD CLEARING
186001	MISC DEFERRED DEBITS
186004	FINANCING EXPENSE
186035	KEY MAN LIFE INSURANCE
186049	PRELIMINARY CELL SITE COSTS
186505	GOODWILL
186548	OTHER INTANGIBLE ASSETS - SHORT TERM
186549	OTHER INTANGIBLE ASSETS
186553	OTH INTANG ASSETS - OVEC PPA ENERGY CONTRACT
186556	OTH INTANG ASSETS - SO2 ALLOWANCES - CURRENT
186557	OTH INTANG ASSETS - NOX OZONE ALLOWANCES - CURRENT
186558	OTH INTANG ASSETS - NOX ANNUAL ALLOWANCES - CURRENT
186559	OTH INTANG ASSETS - SO2 ALLOWANCES - FUTURE
186560	OTH INTANG ASSETS - NOX OZONE ALLOWANCES - FUTURE
186561	OTH INTANG ASSETS - NOX ANNUAL ALLOWANCES - FUTURE
186576	CARROLLTON SALE/LEASEBACK
189091	UNAM LOSS-FMB Series P $33M 05/15
189093	UNAM LOSS-PCB $7.2M REDEEMED
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
190315	DTA FEDERAL - CURRENT
190316	NETTING - DEFERRED TAX ASSETS - CURRENT - FEDERAL
190317	NETTING - DEFERRED TAX LIABILITIES - CURRENT - FEDERAL
190414	DTA ON PROVISIONS FOR PENSIONS - OCI - FED (NON-CURRENT)
190415	DTA FEDERAL - NON-CURRENT
190416	DTA ON FIN 48 - UTP - FEDERAL
190515	DTA STATE - CURRENT
190516	NETTING - DEFERRED TAX ASSETS - CURRENT - STATE
190517	NETTING - DEFERRED TAX LIABILITIES - CURRENT - STATE
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
216101	UNAPP UNDST SUB EARN
219010	ACCUM OCI - EQUITY INVEST EEI

Account Number	Account Description
219011	ACCUM OCI OF SUBS - PTAX
219013	OCI - FAS 158 INCREASE FUNDED STATUS - GROSS
219110	DEFERRED TAX - OCI - EQUITY INVEST EEI
219111	ACCUM OCI OF SUBS - TAX
219113	OCI - FAS 158 INCREASE FUNDED STATUS - TAX
221100	LONG TERM DEBT
223006	LT NOTES PAYABLE TO LG&E AND KU CAPITAL LLC
223014	LT NOTES PAYABLE TO SERVCO
223100	LONG TERM NOTES PAYABLE TO PPL CORP PRINCIPAL
224100	PAA PCB FMV ADJUSTMENT
226100	DEBT DISCOUNT BONDS
228201	WORKERS COMPENSATION
228202	WORKERS COMPENSATION - SHORT-TERM
228301	FASB106-POST RET BEN
228304	PENSION PAYABLE
228305	POST EMPLOYMENT BENEFIT PAYABLE
228306	PENSION PAYABLE SERP
228307	FASB 106 - MEDICARE SUBSIDY
228308	PENSION PAYABLE - SERP - NON-MERCER
228318	PENSION PAYABLE - SERP - NON-MERCER - CURRENT
228325	FASB 112 - POST EMPLOY MEDICARE SUBSIDY
230012	ASSET RETIREMENT OBLIGATIONS - STEAM
230013	ASSET RETIREMENT OBLIGATIONS - TRANSMISSION
230015	ASSET RETIREMENT OBLIGATIONS - DISTRIBUTION
230016	ASSET RETIREMENT OBLIGATIONS - GAS
230017	ASSET RETIREMENT OBLIGATIONS - COMMON
230022	ASSET RETIREMENT OBLIGATIONS - STEAM - ST
230023	ASSET RETIREMENT OBLIGATIONS - TRANSMISSION - ST
230025	ASSET RETIREMENT OBLIGATIONS - DISTRIBUTION - ST
230026	ASSET RETIREMENT OBLIGATIONS - GAS - ST
230027	ASSET RETIREMENT OBLIGATIONS - COMMON - ST
231005	COMMERCIAL PAPER PAYABLE
231006	DISCOUNT ON COMMERCIAL PAPER
231008	ST-NP KU REVOLVING CREDIT $400M 12/14
231019	ST-NP LGE REVOLVING CREDIT $400M 12/14
231020	ST NOTE PAYABLE - ARMORED CAR LAG BACK OFFICES
231100	REVOLVING CREDIT FACILITIES
232001	ACCTS PAYABLE-REG
232002	SALS/WAGES ACCRUED
232008	SUNDRY BILLING REFUNDS
232009	PURCHASING ACCRUAL
232010	WHOLESALE PURCHASES A/P
232011	TRANSMISSION PAYABLE
232014	RECEIVING/INSPECTION ACCRUAL
232015	AP FUEL
232022	ACCRUED AUDIT FEES
232023	ACCRUED TAXABLE OFFICER BENEFITS
232024	CREDIT CASH BALANCE
232027	CREDIT CARD PAYMENTS
232030	RETAINAGE FEES
232042	MISO AND PJM ANCILLARY SERVICES CHARGES A/P
232093	SUSPENSE - CCS
232095	SUSPENSE - SALES TAX BURDEN
232096	SUSPENSE - OTHER BURDENS
232097	SUSPENSE - INVENTORY
232098	SUSPENSE - MANUAL DISABLED
232099	SUSPENSE ACCOUNT
232100	ACCOUNTS PAYABLE-TRADE
232111	401K LIABILITY - EMPLOYER
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
233011	ST - NOTES PAYABLE TO LKE PARENT
233013	ST - NOTES PAYABLE TO SERVCO
233019	SHORT TERM NOTES PAYABLE TO LG&E AND KU CAPITAL CORP
233030	N/P - MONEY POOL LG&E AND KU ENERGY LLC CURRENT
233100	N/P - MONEY POOL LG&E
233102	N/P - MONEY POOL KU
233103	N/P - MONEY POOL LEM
233104	N/P - MONEY POOL FCD
234012	I/C PAYABLE CEP RESERVES
234017	I/C PAYABLE - KU
234051	INTERCOMPANY PENSION PAYABLE
234052	I/C PAYABLE-PPL SERVICES CORPORATION
234053	I/C PAYABLE TO PPL ENERGY SUPPLY
234054	I/C PAYABLE - LGE
234055	I/C PAYABLE-PPL CORPORATION
234092	I/C PAYABLE TO PPL ENERGY FUNDING CORP

Account Number	Account Description
234100	A/P TO ASSOC CO
235001	CUSTOMER DEPOSITS
235002	CUSTOMER DEPOSITS OFF-SYS
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
236035	OTHER TAXES ACCRUED-OPR
236036	REAL ESTATE AND PERSONAL PROPERTY TAXES - NON KY
236115	STATE UNEMPLOYMENT-OPR
236116	FEDERAL UNEMPLOYMENT-OPR
237004	ACCR INT-PCB CC2007A $17.8M 02/26
237005	ACCR INT-PCB TC2007A $8.9M 03/37
237007	ACCR INT-COMMERCIAL PAPER
237008	ACCR INT-KU REVOLVING CREDIT $400M 12/14
237009	ACCR INT-FMB KU2010 $250M 11/15
237010	ACCR INT-FMB KU2010 $500M 11/20
237011	ACCR INT-FMB KU2010 $750M 11/40
237019	ACCR INT-LGE REVOLVING CREDIT $400M 12/14
237020	ACCR INT-FMB LGE2010 $250M 11/15
237021	ACCR INT FMB LGE2010 $285M 11/40
237022	ACCR INT FMB LGE2013 $250M 11/43
237023	ACCR INT FMB KU2013 $250M 11/43
237100	ACCR INT LONG-TERM DEBT
237103	ACCR INT-PCB CC2008A $77.9M 02/32
237125	ACCR INT-PCB LM/JC2007A $31M 06/33
237126	ACCR INT-PCB LM/JC2007B $35.2M 06/33
237127	ACCR INT-PCB TC2007A $60M 06/33
237149	ACCR INT-PCB MERC2000A $12.9M 05/23
237168	ACCR INT FROM FORWARD STARTING SWAP SETTLEMENT
237184	ACCR INT-PCB CC2002A $20.93M 2/32
237185	ACCR INT-PCB CC2002B $2.4M 2/32
237186	ACCR INT-PCB MERC2002A $7.4M 2/32
237187	ACCR INT-PCB MUHC2002A $2.4M 2/32
237188	ACCR INT-PCB CC2002C $96M 10/32
237190	ACCR INT-PCB LM/JC2003A $128M 10/33
237192	ACCR INT-PCB CC2004A $50M 10/34
237194	ACCR INT-PCB LM/JC2005A $40M 2/35
237199	ACCR INT-PCB CC2006B $54M 10/34
237300	INT ACC-OTH LIAB
237301	INTEREST ACCRUED ON CUSTOMER DEPOSITS
237304	INTEREST ACCRUED ON TAX LIABILITIES
238200	DIV PAYABLE - PARENT FM LGE
238203	DIV PAYABLE - PARENT FM KU
238204	DIV PAYABLE - PPL FM LKE
241007	TAX COLL PAY-FICA
241018	STATE WITHHOLDING TAX PAYABLE
241036	LOCAL WITHHOLDING TAX PAYABLE
241037	T/C PAY-PERS INC-FED
241038	T/C PAY-ST SALES/USE
241039	T/C PAY-OCCUP/SCHOOL
241046	CONSUMER UTILITY TAX-VA
241047	SALES TAX-NORTON, VA
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	PENSION PAYABLE - CURRENT
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
242101	RETIREMENT INCOME LIABILITY
242102	IBNP MEDICAL AND DENTAL RESERVE
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

Account Number	Account Description
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
245003	ST DERIV LIAB FAS133 HEDGING - NON-LKE AFFILIATE
245004	LT DERIV LIAB FAS133 HEDGING - NON-LKE AFFILIATE
252011	LINE EXTENSIONS
252012	20% SUPPLEMENT
252013	OTH CUST ADV-CONSTR
252014	CUST OUTDOOR LIGHTING DEPOSITS
252015	MOBILE HOME LINE
252017	LINE EXTENSIONS - SHORT TERM
252018	CUST OUTDOOR LIGHTING DEP - SHORT TERM
252019	20% SUPPLEMENT - SHORT TERM
252101	CUSTOMER ADVANCES - PARTIAL PAYMENTS
253004	OTH DEFERRED CR-OTHR
253005	CL ACC FR OTH DEF DR
253025	DEFERRED COMPENSATION
253027	DEFERRED RENT PAYABLE
253028	OTHER DEFERRED CREDITS-CROSS BORDER LEASE
253031	OTHER LONG TERM OPERATING LIABILITIES
253032	UNCERTAIN TAX POSITION - FEDERAL
253033	UNCERTAIN TAX POSITION - STATE
253034	MCI AMORTIZATION
253037	UNEARNED REVENUE - POLE ATTACHMENTS - LONG-TERM
253038	OTHER DEF. CREDIT - COAL CONTRACT - ST
253039	OTHER DEF. CREDIT - COAL CONTRACT - LT
253040	LEASEHOLD INCENTIVE LG&E CENTER LEASE 07012012 - LONG TERM
253301	PROVISIONS FOR INDEMNITY OBLIGATIONS
253320	UNCERTAIN TAX POSITIONS - INTEREST
253576	DEF GAIN - CARROLLTON SALE/LEASEBACK
254001	FASB 109 ADJ-FED
254002	FASB 109 GR-UP-FED
254003	FASB 109 ADJ-STATE
254004	FASB 109 GR-UP-STATE
254007	REG LIABILITY - GAS SUPPLY CLAUSE
254008	DSM COST RECOVERY
254010	REGULATORY LIABILITY - FAS 158 OPEB
254011	VA FUEL COMPONENT - JURISDICTIONAL CUSTOMERS (CURRENT)
254012	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)
254054	REG. LIABILITY - COAL CONTRACT - ST
254055	REG. LIABILITY - COAL CONTRACT - LT
254056	PAA REG LIABILITY - EMISSION ALLOWANCES - CURRENT
254057	PAA REG LIABILITY - EMISSION ALLOWANCES - LT
254058	PAA REGULATORY LIABILITY - OVEC VALUATION
254100	REG LIAB - LT INTEREST RATE SWAP FORWARD STARTING
254321	MISO EXIT FEE REFUND
254356	VA FUEL COMPONENT - JURISDICTIONAL CUSTOMERS (NON-CURRENT)
255004	ITC TC2
255006	JOB DEVELOP CR
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
283418	DTL FEDERAL - CURRENT
283514	DTL ON PROVISIONS FOR PENSIONS - OCI - FED (NON-CURRENT)
283515	DTL FEDERAL - NON-CURRENT
283519	DTL ON LIABILITIES - EEI -FED (NON-CURRENT)
283618	DTL STATE - 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
403024	DEPREC. EXP. - GENERAL - GAS
403025	DEPREC. EXP. - COMMON
403026	DEPREC. EXP. - STEAM - ECR
403027	DEPREC EXP - ELECTRIC - DSM
403028	DEPREC EXP - GAS - DSM

Account Number	**Account Description**
403029	DEPREC. EXP. - GENERAL - GLT
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
403131	DEPREC EXP ARO COMMON
403181	DEPRECIATION NEUTRALITY - GENERATION DEPRECIATION
403182	DEPRECIATION NEUTRALITY - TRANSMISSION DEPRECIATION
403185	DEPRECIATION NEUTRALITY - DISTRIBUTION DEPRECIATION
403186	DEPRECIATION NEUTRALITY - GAS DEPRECIATION
403187	DEPRECIATION NEUTRALITY - COMMON DEPRECIATON
404301	AMORT-INTANG GAS PLT
404401	AMT-EL INTAN PLT-RTL
404402	AMT-EL INTAN PLT-WHS
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
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
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
411105	ACCRETION EXPENSE - COMMON
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
411802	GAIN-DISP OF ALLOW
412001	SERVICE COMPANY CONSTRUCTION OR OTHER SERVICES EXP
415001	REVENUE FROM CUSTOMER SERVICE LINES
415004	MERCHANDISE SALES
416001	EXPENSES FROM CUSTOMER SERVICE LINES
416004	MERCHANDISE COST OF SALES
417004	SERVICE CHARGE AND SUPERVISORY FEE - IMEA AND IMPA
417005	IMPA-WORKING CAPITAL
417006	IMEA-WORKING CAPITAL
417102	STEAM EXPENSES - (TC ALLOC ONLY)

Account Number	Account Description
417105	ELECTRIC EXPENSES - (TC ALLOC ONLY)
417106	MISC EXPENSES - (TC ALLOC ONLY)
417107	RENTS
417108	OPERATION SUPERVISION / ENGR - (TC ALLOC ONLY)
417109	EMISSION ALLOWANCES - (TC ALLOC ONLY)
417110	MTCE SUPERVISION/ENG - (TC ALLOC ONLY)
417111	MTCE OF STRUCTURES - (TC ALLOC ONLY)
417112	MTCE OF BOILER PLANT - (TC ALLOC ONLY)
417113	MTCE OF ELEC PLANT - (TC ALLOC ONLY)
417114	MTCE OF MISC PLANT - (TC ALLOC ONLY)
417120	ADMIN AND GEN SAL - (TC ALLOC ONLY)
417121	OFFICE SUPP AND EXP - (TC ALLOC ONLY)
417123	OUSIDE SVCE EMPLOYED - (TC ALLOC ONLY)
417124	PROPERTY INSURANCE - (TC ALLOC ONLY)
417125	INJURIES AND DAMAGES - (TC ALLOC ONLY)
417126	EMPL PENSIONS/BEN - (TC ALLOC ONLY)
417129	DUPLICATE CGS - CR - (TC ALLOC ONLY)
417130	MISC GENERAL EXP - (TC ALLOC ONLY)
417131	ADMIN AND GEN RENTS - (TC ALLOC ONLY)
417135	MTCE OF GEN PLANT - (TC ALLOC ONLY)
418001	NONOPR RENT INCOME
418107	EQUITY IN EARNINGS OF SUBS-EEI
418109	AMORTIZATION-EEI PAA
418110	EQUITY IN EARNINGS OF CONSOLIDATED SUBSIDIARIES
418111	IMPAIRMENT OF SUBS - EEI
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
419211	DIVIDENDS FROM OVEC
420003	AMORTIZATION OF ITC
421001	MISC NONOPR INCOME
421003	KM LIFE INS - CASH SURRENDER VALUE
421005	MISC NONOPR INCOME-NON-UTILITY ASSET DEPR
421006	AOCI ADJUSTMENT OF SUBSIDIARY - EEI
421101	GAIN-PROPERTY DISP
421105	GAIN ON ARO SETTLEMENT
421201	LOSS-PROPERTY DISP
421301	PRETAX GAIN/LOSS ON DISPOSAL OF DISC OPERS
421306	PRETAX GAIN/LOSS ON DISPOSAL OF DISC OPERS - CENTURY RECEIVABLE
426101	DONATIONS
426191	DONATIONS - INDIRECT
426201	LIFE INSURANCE
426301	PENALTIES
426401	EXP-CIVIC/POL/REL
426491	EXP-CIVIC/POL/REL - INDIRECT
426501	OTHER DEDUCTIONS
426502	SERP
426504	OFFICERS TIA
426505	OFFICER LONG-TERM INCENT
426509	SERP - NON-MERCER
426511	LOSS ON ASSET IMPAIRMENT
426513	OTHER OFFICER BENEFITS
426514	AOCI ADJUSTMENT OF SUBSIDIARY - EEI
426517	SERP - INTEREST
426518	GOODWILL IMPAIRMENT
426557	AMORT OF OCI-PCB JC2003A $128M
426558	AMORT OF REG ASSET - SWAP TERMINATION
426560	ECONOMIC DEVELOPMENT RIDER-CREDITS EARNED
426591	OTHER DEDUCTIONS - INDIRECT
427007	INT EXP-KU REVOLVING CREDIT $400M 12/14
427019	INT EXP-LGE REVOLVING CREDIT $400M 12/14
427100	INTEREST EXPENSE
427150	INT EXP-PCB JC2000A $25M 11/16
427154	INT EXP-PCB JC2007A $31M 06/17
427155	INT EXP-PCB JC2005A $40M 07/19
427164	INT EXP-SWAP-MS $32M 10/32 3.657%
428009	AM EXP-FMB KU2010 $250M 11/15
428010	AM EXP-FMB KU2010 $500M 11/20
428011	AM EXP-FMB KU2010 $750M 11/40
428023	AM EXP-FMB KU2013 $250M 11/43
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	ANTICIPATED DEBT WITH PPL CORP
431002	INT-CUST DEPOSITS
431003	INT-FED TAX DEFNCY
431004	INT-OTHER TAX DEFNCY

Account Number	Account Description
431008	INT-DSM COST RECOVER
431009	INT-SHORT TERM DEBT-CP
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
431200	OTHER INTEREST EXPENSE
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
440010	RESID (FUEL) - KWH - (STAT ONLY)
440011	RESID (FUEL) - CUS - (STAT ONLY)
440012	ELECTRIC RESIDENTIAL KW
440101	ELECTRIC RESIDENTIAL DSM
440102	ELECTRIC RESIDENTIAL ENERGY NON-FUEL REV
440103	ELECTRIC RESIDENTIAL ENERGY FUEL REV
440104	ELECTRIC RESIDENTIAL FAC
440111	ELECTRIC RESIDENTIAL ECR
440112	ELECTRIC RESIDENTIAL MSR
440113	ELECTRIC RESIDENTIAL ESM
440114	ELECTRIC RESIDENTIAL VDT
440116	ELECTRIC RESIDENTIAL DEMAND ECR
440117	ELECTRIC RESIDENTIAL ENERGY ECR
440118	ELECTRIC RESIDENTIAL DEMAND CHG REV
440119	ELECTRIC RESIDENTIAL CUST CHG REV
442010	SM COMRC/IND SALE-EL - KWH - (STAT ONLY)
442011	SM COMRC/IND SALE-EL - CUS - (STAT ONLY)
442012	SM COMRC/IND SALE-EL - KW - (STAT ONLY)
442020	LG COMMERC SALES-EL - KWH - (STAT ONLY)
442021	LG COMMERC SALES-EL - CUS - (STAT ONLY)
442022	LG COMMERC SALES-EL - KW - (STAT ONLY)
442025	KU COMMERCIAL SALES - KWH - (STAT ONLY)
442026	KU COMMERCIAL SALES - CUS - (STAT ONLY)
442027	KU COMMERCIAL SALES - KW - (STAT ONLY)
442030	LG INDUSTR SALES-El-OTHER - KWH - (STAT ONLY)
442031	LG INDUSTR SALES-EL-OTHER - CUS - (STAT ONLY)
442034	LG INDUSTR SALES-EL-OTHER - KW - (STAT ONLY)
442035	KU INDUSTRIAL SALES - KWH - (STAT ONLY)
442036	KU INDUSTRIAL SALES - CUS - (STAT ONLY)
442037	KU INDUSTRIAL SALES - KW - (STAT ONLY)
442065	MINE POWER SALES (COAL) - KWH - (STAT ONLY)
442066	MINE POWER SALES (COAL) - CUS - (STAT ONLY)
442067	MINE POWER SALES (COAL) - KW - (STAT ONLY)
442101	ELECTRIC SMALL COMMERCIAL DSM
442102	ELECTRIC SMALL COMMERCIAL ENERGY NON-FUEL REV
442103	ELECTRIC SMALL COMMERCIAL ENERGY FUEL REV
442104	ELECTRIC SMALL COMMERCIAL FAC
442105	ELECTRIC SMALL COMMERCIAL STOD
442111	ELECTRIC SMALL COMMERCIAL ECR
442112	ELECTRIC SMALL COMMERCIAL MSR
442113	ELECTRIC SMALL COMMERCIAL ESM
442114	ELECTRIC SMALL COMMERCIAL VDT
442116	ELECTRIC SMALL COMMERCIAL DEMAND ECR
442117	ELECTRIC SMALL COMMERCIAL ENERGY ECR
442118	ELECTRIC SMALL COMMERCIAL DEMAND CHG REV
442119	ELECTRIC SMALL COMMERCIAL CUST CHG REV
442201	ELECTRIC LARGE COMMERCIAL DSM
442202	ELECTRIC LARGE COMMERCIAL ENERGY NON-FUEL REV
442203	ELECTRIC LARGE COMMERCIAL ENERGY FUEL REV
442204	ELECTRIC LARGE COMMERCIAL FAC
442205	ELECTRIC LARGE COMMERCIAL STOD
442211	ELECTRIC LARGE COMMERCIAL ECR
442212	ELECTRIC LARGE COMMERCIAL MSR
442213	ELECTRIC LARGE COMMERCIAL ESM
442214	ELECTRIC LARGE COMMERCIAL VDT
442216	ELECTRIC LARGE COMMERCIAL DEMAND ECR
442217	ELECTRIC LARGE COMMERCIAL ENERGY ECR
442218	ELECTRIC LARGE COMMERCIAL DEMAND CHG REV
442219	ELECTRIC LARGE COMMERCIAL CUST CHG REV
442301	ELECTRIC INDUSTRIAL DSM
442302	ELECTRIC INDUSTRIAL ENERGY NON-FUEL REV
442303	ELECTRIC INDUSTRIAL ENERGY FUEL REV
442304	ELECTRIC INDUSTRIAL FAC
442305	ELECTRIC INDUSTRIAL STOD
442311	ELECTRIC INDUSTRIAL ECR
442312	ELECTRIC INDUSTRIAL MSR
442313	ELECTRIC INDUSTRIAL ESM
442314	ELECTRIC INDUSTRIAL VDT

Account Number	Account Description
442316	ELECTRIC INDUSTRIAL DEMAND ECR
442317	ELECTRIC INDUSTRIAL ENERGY ECR
442318	ELECTRIC INDUSTRIAL DEMAND CHG REV
442319	ELECTRIC INDUSTRIAL CUST CHG REV
442601	MINE POWER DSM
442602	MINE POWER ENERGY NON-FUEL REV
442603	MINE POWER ENERGY FUEL REV
442604	MINE POWER FAC
442605	MINE POWER STOD
442611	MINE POWER ECR
442612	MINE POWER MSR
442613	MINE POWER ESM
442614	MINE POWER VDT
442616	MINE POWER DEMAND ECR
442617	MINE POWER ENERGY ECR
442618	MINE POWER DEMAND CHG REV
442619	MINE POWER CUST CHG REV
444010	PUBLIC ST/HWY LIGHTS - KWH - (STAT ONLY)
444011	PUBLIC ST/HWY LIGHTS - CUS - (STAT ONLY)
444012	PUBLIC ST/HWY LIGHTS - KW - (STAT ONLY)
444101	ELECTRIC STREET LIGHTING DSM
444102	ELECTRIC STREET LIGHTING ENERGY NON-FUEL REV
444103	ELECTRIC STREET LIGHTING ENERGY FUEL REV
444104	ELECTRIC STREET LIGHTING FAC
444105	ELECTRIC STREET LIGHTING STOD
444111	ELECTRIC STREET LIGHTING ECR
444112	ELECTRIC STREET LIGHTING MSR
444113	ELECTRIC STREET LIGHTING ESM
444114	ELECTRIC STREET LIGHTING VDT
444117	ELECTRIC STREET LIGHTING ENERGY ECR
444118	ELECTRIC STREET LIGHTING DEMAND CHG REV
444119	ELECTRIC STREET LIGHTING CUST CHG REV
445010	SALES-PUB AUTH-ELEC - KWH - (STAT ONLY)
445011	SALES-PUB AUTH-ELEC - CUS - (STAT ONLY)
445012	SALES-PUB AUTH-ELEC - KW - (STAT ONLY)
445030	MUNICIPAL PUMPING - KWH - (STAT ONLY)
445031	MUNICIPAL PUMPING - CUS - (STAT ONLY)
445032	MUNICIPAL PUMPING - KW - (STAT ONLY)
445101	ELECTRIC PUBLIC AUTH DSM
445102	ELECTRIC PUBLIC AUTH ENERGY NON-FUEL REV
445103	ELECTRIC PUBLIC AUTH ENERGY FUEL REV
445104	ELECTRIC PUBLIC AUTH FAC
445105	ELECTRIC PUBLIC AUTH STOD PCR
445111	ELECTRIC PUBLIC AUTH ECR
445112	ELECTRIC PUBLIC AUTH MSR
445113	ELECTRIC PUBLIC AUTH ESM
445114	ELECTRIC PUBLIC AUTH VDT
445116	ELECTRIC PUBLIC AUTH DEMAND ECR
445117	ELECTRIC PUBLIC AUTH ENERGY ECR
445118	ELECTRIC PUBLIC AUTH DEMAND CHG REV
445119	ELECTRIC PUBLIC AUTH CUST CHG REV
445301	MUNI PUMPING DSM
445302	MUNI PUMPING ENERGY NON-FUEL REV
445303	MUNI PUMPING ENERGY FUEL REV
445304	MUNI PUMPING FAC
445305	MUNICIPAL PUMPING STOD
445311	MUNI PUMPING ECR
445312	MUNI PUMPING MSR
445313	MUNI PUMPING ESM
445314	MUNI PUMPING VDT
445316	MUNI PUMPING DEMAND ECR
445317	MUNI PUMPING ENERGY ECR
445318	MUNI PUMPING DEMAND CHG REV
445319	MUNI PUMPING CUST CHG REV
447005	I/C SALES - OSS
447006	I/C SALES NL
447010	FIRM SALES - ENERGY-OTHER - KWH - (STAT ONLY)
447011	FIRM SALES - ENERGY-OTHER - CUS - (STAT ONLY)
447017	FIRM SALES - ENERGY-OTHER - KW - (STAT ONLY)
447021	FIRM SALES - MUNI/BEREA - KWH - (STAT ONLY)
447022	FIRM SALES - MUNI/BEREA - CUS
447023	FIRM SALES - MUNICIPALS - KW - (STAT ONLY)
447049	SPOT SALES - ENERGY
447050	OFF-SYSTEM SALES REVENUE TO THIRD PARTIES
447051	SPOT SALES - ENERGY - KW - (STAT ONLY)
447100	BROKERED SALES
447110	SETTLED SWAP REVENUE
447200	BROKERED PURCHASES
447302	RESALE MUNICIPALS BASE REV
447303	RESALE MUNICIPALS BASE REV FUEL
447304	RESALE MUNICIPALS FAC
447318	RESALE MUNICIPALS DEMAND CHG REV
447319	RESALE MUNICIPALS CUST CHG REV
449102	PROVISION FOR RATE REFUND/COLLECTION
449105	RATE REFUNDS-RETAIL
450001	FORFEITED DISC/LATE PAYMENT CHARGE-ELEC

Account Number	Account Description
450002	FORFEITED DISC/LATE PAYMENT CHARGE - MUNI INTEREST
451001	RECONNECT CHRG-ELEC
451002	TEMPORARY SERV-ELEC
451004	OTH SERVICE REV-ELEC
454001	CATV ATTACH RENT
454002	OTH RENT-ELEC PROP
454003	RENT FRM FIBER OPTIC
454006	FACILITY CHARGES
454900	I/C JOINT USE RENT REVENUE-ELEC-INDIRECT
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
456022	COAL RESALE REVENUES
456028	EXCESS FACILITIES CHARGES/NRB ELECTRIC REV (ENDED 04/09)
456029	GYPSUM REVENUES
456030	FORFEITED REFUNDABLE ADVANCES
456099	POWER DELIVERED TO GOVERNMENT (STAT ONLY)
456101	BASE OTHER ELECTRIC REVENUES-WHEELING-MISO - (STAT ONLY)
456102	ANCILLARY SERVICE SCHEDULE 1-MISO
456103	ANCILLARY SERVICE SCHEDULE 2-MISO
456105	ANCILLARY SERVICE SCHEDULE 1-OSS-MISO
456106	ANCILLARY SERVICE SCHEDULE 2-OSS-MISO
456109	NL TRANSMISSION OF ELECTRIC ENERGY-3RD PARTY
456114	INTERCOMPANY TRANSMISSION REVENUE - RETAIL SOURCING OSS
456116	INTERCOMPANY TRANSMISSION REVENUE - MUNICIPALS
456118	INTRACOMPANY TRANSMISSION REVENUE - NATIVE LOAD
456119	INTRACOMPANY TRANSMISSION REVENUE - RETAIL SOURCING OSS
456124	I/C TRANSMISSION RETAIL REVENUE - NATIVE LOAD
456127	TRANSMISSION SERVICE REVENUE - CC (OSS-STAT ONLY)
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)
480011	RESID VARIABLE(FUEL) - CUS - (STAT ONLY)
480101	GAS RESIDENTIAL DSM
480102	GAS RESIDENTIAL ENERGY REV
480104	GAS RESIDENTIAL GSC
480106	GAS RESIDENTIAL GLT
480107	GAS RESIDENTIAL WNA
480114	GAS RESIDENTIAL VDT
480119	GAS RESIDENTIAL CUST CHG REV
481010	COMMERCIAL SALES-GAS - CU - (STAT ONLY)
481011	COMMERCIAL SALES-GAS - MCF - (STAT ONLY)
481020	INDUSTRIAL SALES-GAS - CU - (STAT ONLY)
481021	INDUSTRIAL SALES-GAS - MCF - (STAT ONLY)
481101	GAS COMMERCIAL DSM
481102	GAS COMMERCIAL ENERGY REV
481104	GAS COMMERCIAL GSC
481105	GAS COMMERCIAL CASHOUT
481106	GAS COMMERICAL GLT
481107	GAS COMMERCIAL WNA
481114	GAS COMMERCIAL VDT
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
481214	GAS INDUSTRIAL VDT
481219	GAS INDUSTRIAL CUST CHG REV

Account Number	Account Description
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
482107	GAS PUBLIC AUTH WNA
482114	GAS PUBLIC AUTH VDT
482119	GAS PUBLIC AUTH CUST CHG REV
483001	OFF SYSTEM SALES FOR RESALE (MCF) - (STAT ONLY)
484001	GAS INTERDEPARTMENTAL SALES
484102	GAS INTERDEPARTMENTAL BASE REVENUES
484104	GAS INTERDEPARTMENTAL GSC
484105	PADDYS RUN CASHOUT - INTRACOMPANY
484106	GAS INTERDEPARTMENTAL GLT
484119	GAS INTERDEPARTMENTAL CUSTOMER CHARGE
487001	FORFEITED DISC/LATE PAYMENT CHARGE-GAS
488001	RECONNECT CHRG-GAS
488003	INSPECTION CHARGE-GAS
488004	METER TESTS-GAS
488005	GAS METER PULSE SERVICE
489201	GAS TRANSPORT INTERDEPARTMENTAL - BASE
489204	GAS TRANSPORT INTERDEP - CASHOUT OFO/UCDI
489215	GAS TRANSPORT - INTERDEPARTMENTAL
489301	GAS TRANSPORT - DSM
489302	GAS TRANSPORT - INDUSTRIAL
489304	GAS TRANSPORT - CASHOUT OFO/UCDI
489310	GAS TRANSPORT - CUSTOMERS (STAT ONLY)
489312	GAS TRANSPORT - DIRECT PAY - STATS ONLY
489314	GAS TRANSPORT - VDT
489319	TRANSPORT GAS - CUSTOMER CHARGE
489322	GAS TRANSPORT - COMMERCIAL
489332	GAS TRANSPORT - PUBLIC AUTHORITY
493001	RENT-GAS PROPERTY
493900	I/C JOINT USE RENT REVENUE-GAS-INDIRECT
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
495102	PURCHASED GAS REFUND
495103	OVER/UNDER GAS SUPPLY COST ACTUAL ADJ
495104	OVER/UNDER GAS SUPPLY COST BALANCE ADJ
495107	WHOLESALE SALES MARGIN
495108	ACQ AND TRANS INCENTIVE
495109	PRB RECOVERY
500100	OPER SUPER/ENG
500900	OPER SUPER/ENG - INDIRECT
501001	FUEL-COAL - TON
501002	FUEL-COAL - BTU - (STAT ONLY)
501003	COAL ADDITIVES
501004	FUEL COAL - TO SOURCE UTILITY OSS
501005	FUEL COAL - OSS
501006	FUEL COAL - OFFSET
501007	FUEL COAL - TO SOURCE UTILITY RETAIL
501020	START-UP OIL -GAL
501021	START-UP OIL - BTU - (STAT ONLY)
501022	STABILIZATION OIL - GAL
501023	STABILIZATION OIL - BTU - (STAT ONLY)
501024	GENERATION OIL - GAL - (STAT ONLY)
501025	GENERATION OIL - BTU - (STAT ONLY)
501026	COAL RESALE EXPENSES
501030	PETROLEUM COKE - TON - (STAT ONLY)
501090	FUEL HANDLING
501091	FUEL SAMPLING AND TESTING
501092	FUEL HANDLING-GALS - (STAT ONLY)
501099	KWH GENERATED-COAL - (STAT ONLY)
501100	START-UP GAS - MCF
501101	START-UP GAS - BTU - (STAT ONLY)
501102	STABILIZATION GAS - MCF
501103	STABILIZATION GAS - BTU - (STAT ONLY)
501110	GENERATION GAS - MAIN BOILER -MCF - (STAT ONLY)
501200	BOTTOM ASH DISPOSAL
501201	PLANT-ECR BOTTOM ASH DISPOSAL
501202	BOTTOM ASH PROCEEDS
501203	ECR BOTTOM ASH DISPOSAL
501250	FLY ASH PROCEEDS
501251	FLY ASH DISPOSAL
501252	PLANT-ECR FLY ASH DISPOSAL
501253	ECR FLY ASH DISPOSAL
501299	KWH GENERATED-OIL - (STAT ONLY)
501990	FUEL HANDLING - INDIRECT
501993	FUELS PROCUREMENT - INDIRECT
502001	OTHER WASTE DISPOSAL
502002	BOILER SYSTEMS OPR
502003	SDRS OPERATION

Account Number	**Account Description**
502004	SDRS-H2O SYS OPR
502005	SLUDGE STAB SYS OPR
502006	SCRUBBER REACTANT EX
502011	ECR OTHER WASTE DISPOSAL
502012	PLANT-ECR LANDFILL OPERATION
502013	ECR LANDFILL OPERATIONS
502021	OTHER WASTE DISPOSAL - RETAIL
502022	OTHER WASTE DISPOSAL - OSS
502023	OTHER WASTE DISPOSAL - OFFSET
502024	SCRUBBER REACTANT - RETAIL
502025	SCRUBBER REACTANT - OSS
502026	SCRUBBER REACTANT - OFFSET
502056	ECR SCRUBBER REACTANT EX
502100	STM EXP(EX SDRS.SPP)
502900	STM EXP(EX SDRS.SPP) - INDIRECT
504001	STEAM XFERRED - CR - PROJECT USE
505100	ELECTRIC SYS OPR
506001	STEAM OPERATION-AIR QUALITY MONITORING AND CONTROL EQUIPMENT
506051	ECR STEAM OPERATION-AIR QUALITY MONITORING AND CONTROL EQUIPMENT
506100	MISC STM PWR EXP
506102	MISC STM PWR EXP-GALS - (STAT ONLY)
506103	MISC STM PWR EXP-BTU - (STAT ONLY)
506104	NOX REDUCTION REAGENT
506105	OPERATION OF SCR/NOX REDUCTION EQUIP
506106	SCR/NOX - RETAIL
506107	SCR/NOX - OSS
506108	SCR/NOX - OFFSET
506109	SORBENT INJECTION OPERATION
506110	MERCURY MONITORS OPERATIONS
506111	ACTIVATED CARBON
506112	SORBENT REACTANT - REAGENT ONLY
506150	ECR MERCURY MONITORS OPERATIONS
506151	ECR ACTIVATED CARBON
506152	ECR SORBENT REACTANT - REAGENT ONLY
506154	ECR NOX REDUCTION REAGENT
506155	ECR OPERATION OF SCR/NOX REDUCTION EQUIP
506156	ECR BAGHOUSE OPERATIONS
506159	ECR SORBENT INJECTION OPERATION
506900	MISC STM PWR EXP - INDIRECT
507100	RENTS-STEAM
507900	I/C JOINT USE RENT EXPENSE-GEN-INDIRECT
509002	SO2 EMISSION ALLOWANCES
509003	NOX EMISSION ALLOWANCES
509004	EMISSION ALLOWANCES - RETAIL
509007	EMISSION ALLOWANCES - OSS
509008	EMISSION ALLOWANCES - OFFSET
509052	ECR SO2 EMISSION ALLOWANCES
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
512017	MTCE-SLUDGE STAB SYS
512051	ECR INSTR/CNTRL-ENVRNL
512055	ECR MAINTENANCE-SDRS
512100	MTCE-BOILER PLANT
512101	MAINTENANCE OF SCR/NOX REDUCTION EQUIP
512102	SORBENT INJECTION MAINTENANCE
512103	MERCURY MONITORS MAINTENANCE
512105	PLANT-ECR LANDFILL MAINTENANCE
512106	PLANT-ECR CCP SYSTEM MAINTENANCE
512107	ECR LANDFILL MAINTENANCE
512108	ECR CCP SYSTEM MAINTENANCE
512151	ECR MAINTENANCE OF SCR/NOX REDUCTION EQUIP
512152	ECR SORBENT INJECTION MAINTENANCE
512153	ECR MERCURY MONITORS MAINTENANCE
512156	ECR BAGHOUSE MAINTENANCE
513100	MTCE-ELECTRIC PLANT
513900	MTCE-ELECTRIC PLANT - BOILER
514100	MTCE-MISC/STM PLANT
535100	OPER SUPER/ENG-HYDRO
536100	WATER FOR POWER
536101	KWH GENERATED-HYDRO - (STAT ONLY)
538100	ELECTRIC EXPENSES - HYDRO
539100	MISC HYD PWR GEN EXP
540100	RENTS-HYDRO
541100	MTCE-SUPER/ENG - HYDRO
542100	MAINT OF STRUCTURES - HYDRO
543100	MTCE-RES/DAMS/WATERW
544100	MTCE-ELECTRIC PLANT
545100	MTCE-MISC HYDAULIC PLANT
546100	OPER SUPER/ENG - TURBINES
547010	KWH GEN-OTH PWR-OIL - (STAT ONLY)
547020	KWH GEN-OTH PWR-GAS - (STAT ONLY)

Account Number	Account Description
547030	FUEL-GAS - MCF
547031	FUEL-GAS - BTU - (STAT ONLY)
547040	FUEL-OIL - GAL
547041	FUEL-OIL - BTU - (STAT ONLY)
547051	FUEL - TO SOURCE UTILITY OSS
547052	FUEL - OSS
547053	FUEL - OFFSET
547054	FUEL - TO SOURCE UTILITY RETAIL
547056	FUEL - GAS - INTRACOMPANY
547057	FUEL - GAS - INTRACOMPANY - BTU - (STAT ONLY)
548100	GENERATION EXP
549002	AIR QUALITY EXPENSES
549003	NOX EMISSION ALLOWANCES
549100	MISC OTH PWR GEN EXP
550100	RENTS-OTH PWR
551100	MTCE-SUPER/ENG - TURBINES
552100	MTCE-STRUCTURES - OTH PWR
553100	MTCE-GEN/ELECT EQ
554100	MTCE-MISC OTH PWR GEN
554200	MTC-HEAT RECOVERY STEAM GEN
555010	OSS POWER PURCHASES
555015	NL POWER PURCHASES - ENERGY
555016	NL POWER PURCHASES - DEMAND
555020	OSS I/C POWER PURCHASES
555025	NL I/C POWER PURCHASES
555080	PURCHASE POWER NATIVE LOAD - SQF AND LQF TARIFF
555085	PURCHASE POWER NATIVE LOAD DEMAND - LQF TARIFF
555101	INAD INTER REC-KWH - (STAT ONLY)
555110	INAD INTER DEL-KWH - (STAT ONLY)
556100	SYS CTRL / DISPATCHING
556900	SYS CTRL / DISPATCHING - INDIRECT
557100	OTH POWER SUPPLY EXP
557110	MARKET FEES - NATIVE LOAD
557111	MARKET FEES - OFF SYSTEM SALES
557206	MISO DAY 2 OTHER - NATIVE LOAD
557207	MISO DAY 2 OTHER - OFF SYSTEM SALES
557208	RTO OTHER (NON-MISO) - NL
557209	RTO OTHER (NON-MISO) - OSS
557211	RTO OPERATING RESRV (NON-MISO) - NL
557212	RTO OPERATING RESRV (NON-MISO) - OSS
557999	KU PLANT ALLOCATION CLEARING ACCOUNT
560100	OP SUPER/ENG-SSTOPER
560900	OP SUPER/ENG-SSTOPER - INDIRECT
561100	LOAD DISPATCH-WELOB
561190	LOAD DISPATCH - INDIRECT
561291	LOAD DISPATCH-MONITOR AND OPERATE TRANSMISSION SYSTEM - INDIRECT
561391	LOAD DISPATCH-TRANSMISSION SERVICE AND SCHEDULING - INDIRECT
561402	MISO DAY 1 SCH 10 - RESERVE
561403	NL MISO D1 SCHEDULE 10 - SCHEDULING, SYSTEM CONTROLS
561501	RELIABILITY, PLANNING AND STANDARDS DEVELOPMENT
561590	RELIABILITY, PLANNING AND STANDARDS DEVELOPMENT - INDIRECT
561601	TRANSMISSION SERVICE STUDIES
561801	MISO DAY 1 SCH 10 - LOAD
561802	MISO DAY 1 SCH 10 - RESERVE
561803	NL MISO D1 SCHEDULE 10 - RELIABILITY PLANNING
561900	LOAD DISPATCH-WELOB - INDIRECT
561901	BALANCING AUTHORITY EXPENSE (LABOR ONLY)
562100	STA EXP-SUBST OPER
563100	OTHER INSP-ELEC TRAN
563900	OTHER INSP-ELEC TRAN - INDIRECT
565002	TRANSMISSION ELECTRIC OSS
565005	TRANSMISSION ELECTRIC NATIVE LOAD
565006	TRANSMISSION ELECTRIC OSS - MISO
565007	TRANSMISSION ELECTRIC OSS - 3RD PARTY
565014	INTERCOMPANY TRANSMISSION EXPENSE
565016	INTERCOMPANY TRANSMISSION EXPENSE - MUNICIPALS
565018	INTRACOMPANY TRANSMISSION EXPENSE - NATIVE LOAD
565019	INTRACOMPANY TRANSMISSION EXPENSE - OSS
565024	I/C TRANSMISSION RETAIL EXPENSE - NATIVE LOAD
565198	INTRACOMPANY TRANSMISSION EXPENSE OFFSET - NATIVE LOAD
565199	INTRACOMPANY TRANSMISSION EXPENSE ELIMINATION - RETAIL SOURCING OSS
566100	MISC TRANS EXP-SSTMT
566122	REACTIVE SUPPLY & VOLTAGE CONTROL - NL
566140	INDEPENDENT OPERATOR
566150	EKPC DEPANCAKING SETTLEMENT
566151	TRANSMISSION DEPANCAKING EXPENSES
566900	MISC TRANS EXP-SSTMT - INDIRECT
567100	RENTS-ELEC/SUBSTATION OPERATIONS
567900	I/C JOINT USE RENT EXPENSE-TRANS-INDIRECT
569100	MTCE-STRUCT-SSTMTCE
569101	MAINTENANCE OF COMPUTER HARDWARE
570100	MTCE-ST EQ-SSTMTCE
570900	MTCE-ST EQ-SSTMTCE - INDIRECT
571100	MTCE OF OVERHEAD LINES
573100	MTCE-MISC TR PLT-SSTMT
573900	MTCE-MISC TR PLT-SSTMT INDIRECT

Account Number	**Account Description**
575701	MISO DAY 2 SCH 17-MARKET ADMIN FEE-OSS
575702	MISO DAY 2 SCH 16-FTR ADMIN FEE-NL
575703	MISO DAY 2 SCH 17-MARKET ADMIN FEE-NL
575704	MISO DAY 1 SCH 10 - RESERVE
575708	NL MISO D1 SCHEDULE 10 - MKT ADMIN
580100	OP SUPER/ENG-SSTOPER
580900	OP SUPER/ENG-SSTOPER - INDIRECT
581900	SYS CTRL/SWITCH-DIST - INDIRECT
582100	STATION EXP-SSTOPER
583001	OPR-O/H LINES
583003	O/H LOAD/VOLT TEST
583004	INST/REMV TEMP SERV
583005	CUST COMPL RESP-O/H
583008	INST/REMV TRANSF/REG
583009	INSPC O/H LINE FACIL
583010	LOC O/H ELEC FAC-BUD
583100	O/H LINE EXP-SSTOPER
584001	OPR-UNDERGRND LINES
584002	INSPC U/G LINE FACIL
584003	LOAD/VOLT TEST-U/G
584005	RESP-U/G CUST COMPL
584008	INST/RMV/REPL TRANSF
585100	STREET LIGHTING AND SIGNAL SYST EXP
586100	METER EXP
586101	INPECT/TEST METERS
586900	METER EXP - INDIRECT
587100	CUST INSTALLATION EXP
588100	MISC DIST EXP-SUBSTATION OPERATIONS
588900	MISC DIST EXP-SUBSTATION OPERATIONS - INDIRECT
589100	RENTS-DISTR / SUBSTAT OPER
590100	MTCE/SUPER/ENG-SSTMT
590900	MTCE/SUPER/ENG-SSTMT - INDIRECT
591003	MTCE-MISC STRUCT-DIS
592100	MTCE-ST EQ-SSTMTCE
593001	MTCE-POLE/FIXT-DISTR
593002	MTCE-COND/DEVICE-DIS
593003	MTCE-SERVICES
593004	TREE TRIMMING
593005	MINOR EXEMPT EXPENSE
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
598100	MTCE OF MISC DISTRIBUTION PLANT
598900	MTCE OF MISC DISTRIBUTION PLANT - INDIRECT
803001	GAS TRANS LINE PURCH
803002	PURCHASED GAS REFUND
803003	GAS COST ACTUAL ADJ
803004	GAS COST BALANCE ADJ
803006	PURCHASED GAS - WHOLESALE SALES
803007	WHOLESALE SALES MARGIN
803008	ACQ AND TRANS INCENTIVE
803009	PBR RECOVERY
803010	END USERS GAS PURCHASE (MCF ONLY) - (STAT ONLY)
806001	EXCHANGE GAS - INJECTIONS
806002	EXCHANGE GAS - WITHDRAWALS
807401	PURCH GAS CALC EXP
807501	OTHER PURCH GAS EXP
807502	GAS PROCUREMENT EXP
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
812040	GAS-START/STABIL-CR - MCF - (STAT ONLY)
812041	GAS-START/STABIL-CR - BTU - (STAT ONLY)
813001	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	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

Account Number	Account Description
836100	MTCE-PURIFICATION EQUP
837100	MTCE-OTHER EQUIP
850100	OPR SUPV AND ENGR
851100	SYS CTRL/DSPTCH-GAS
852100	OPR-COM EQ-GAS TRANS
856100	MAINS EXPENSES
860100	RENTS-GAS TRANS
863100	MTCE-GAS MAINS-TRANS
871100	DISTR LOAD DISPATCH
874001	OTHER MAINS/SERV EXP
874002	LEAK SUR-DIST MN/SVC
874005	CHEK STOP BOX ACCESS
874006	PATROLLING MAINS
874007	CHEK/GREASE VALVES
874008	OPR-ODOR EQ
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	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
894100	MTCE-OTHER EQUIP
901001	SUPV-CUST ACCTS
901900	SUPV-CUST ACCTS - INDIRECT
902001	METER READ-SERV AREA
902002	METER READ-CLER/OTH
902900	METER READ-SERV AREA - INDIRECT
903001	AUDIT CUST ACCTS
903002	BILL SPECIAL ACCTS
903003	PROCESS METER ORDERS
903006	CUST BILL/ACCTG
903007	PROCESS PAYMENTS
903008	INVEST THEFT OF SVC
903011	MAINTENANCE-CIS
903012	PROC CUST CNTRT/ORDR
903013	HANDLE CREDIT PROBS
903022	COLL OFF-LINE BILLS
903023	PROC BANKRUPT CLAIMS
903025	MTCE-ASST PROGRAMS
903030	PROC CUST REQUESTS
903031	PROC CUST PAYMENTS
903032	DELIVER BILLS-REG
903035	COLLECTING-OTHER
903036	CUSTOMER COMPLAINTS
903038	MISC CASH OVERAGE/SHORTAGE
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
904002	UNCOLLECTABLE ACCTS - WHOLESALE
904003	UNCOLL ACCTS - A/R MISC
904004	UNCOLL ACCTS - A/R MISC - SPEC ITEM
904005	UNCOLLECTIBLE ACCTS - GSC
905001	MISC CUST SERV EXP
905002	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
908001	CUST MKTG/ASSIST

Account Number	Account Description
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	RES CONS/ENG ED PROG - INDIRECT
908909	MISC MARKETING EXP - INDIRECT
909004	MISC CUST COM-SER/IN
909005	MEDIA RELATIONS
909010	PRINT ADVER-SER/INFO
909011	OTH ADVER-SER/INFO
909013	SAFETY PROGRAMS
909910	PRINT ADVER-SER/INFO - INDIRECT
909911	OTHER ADVER-SER/INFO - INDIRECT
910001	MISC CUST SER/INFO
910900	MISC CUST SER/INFO - INDIRECT
912003	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
921002	EXP-GEN OFFICE EMPL
921003	GEN OFFICE SUPPL/EXP
921004	OPR-GEN OFFICE BLDG
921902	INDIRECT EMPLOYEE OFFICE EXPENSE ALLOCATION
921903	GEN OFFICE SUPPL/EXP - INDIRECT
921904	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 - PWC
923301	OUTSIDE SERVICES - AUDIT FEES - OTHER
923302	OUTSIDE SERVICES - TAX SERVICES - 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	SAFETY & INDUSTRIAL HEALTH - INDIRECT
926001	TUITION REFUND PLAN
926002	GROUP LIFE INSURANCE EXPENSE - BURDENS
926003	MEDICAL INSURANCE EXPENSE - BURDENS
926004	DENTAL INSURANCE EXPENSE - BURDENS
926005	LONG TERM DISABILITY EXPENSE - BURDENS
926019	OTHER BENEFITS EXPENSE - BURDENS
926100	EMPLOYEE BENEFITS - NON-BURDEN
926101	PENSIONS EXPENSE - BURDENS
926102	401K EXPENSE - BURDENS
926105	FASB 112 (OPEB) POST EMPLOYMENT EXPENSE - BURDENS
926106	FASB 106 (OPEB) POST RETIREMENT EXPENSE - BURDENS
926110	EMPLOYEE WELFARE
926112	PENSION EXP- VA
926113	PENSION EXP- FERC
926115	ADOPTION ASSISTANCE PROGRAM
926116	RETIREMENT INCOME EXPENSE - BURDENS
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
926910	EMPLOYEE WELFARE - INDIRECT
926911	PENSIONS EXPENSE - BURDENS INDIRECT
926912	401K EXPENSE - BURDENS INDIRECT
926915	FASB 112 (OPEB) POST EMPLOYMENT EXPENSE - BURDENS INDIRECT
926916	FASB 106 (OPEB) POST RETIREMENT EXPENSE - BURDENS INDIRECT
926917	PENSION INTEREST EXPENSE - BURDENS INDIRECT
926918	FASB 106 INTEREST (OPEB) POST RETIREMENT EXPENSE - BURDENS INDIRECT
926919	OTHER BENEFITS EXPENSE - BURDENS INDIRECT
926990	RETIREMENT INCOME EXPENSE - BURDENS INDIRECT
927001	ELEC SUPPL W/O CH-DR
927002	OTH ITEMS W/O CH-DR
927003	CITY OF LOU GAS FRAN
928001	FORMAL CASES - FERC
928002	REG UPKEEP ASSESSMTS
928003	AMORTIZATION OF RATE CASE EXPENSES
928006	FORMAL CASES - TENNESSEE
928007	FORMAL CASES - VIRGINIA

Account Number	Account Description
928008	FORMAL CASES - KENTUCKY
929001	FRANCHISE REQMTS-CR
929002	ELEC USED-ELEC DEPT
929003	GAS USED-GAS DEPT
929004	ELECTRICITY USED - OTHER DEPARTMENTS
929005	ELECTRICITY USED BY ELECTRIC DEPARTMENT - ODP
929006	KWH SOURCES - ODP - (STAT ONLY)
929007	ODP FREE LIGHTING
930101	GEN PUBLIC INFO EXP
930191	GEN PUBLIC INFO EXP - INDIRECT
930201	MISC CORPORATE EXP
930202	ASSOCIATION DUES
930203	RESEARCH WORK
930207	OTHER MISC GEN EXP
930223	SUSPENSE - PPL
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
935203	SOFTWARE MTCE AGREEMENTS
935391	MTCE-COMMUNICATION EQ - INDIRECT
935401	MTCE-OTH GEN EQ
935402	MAINT. OF NON-BONDABLE GENERAL PLANT
935403	MNTC BONDABLE PROPERTY
935488	MTCE-OTH GEN EQ - INDIRECT
951002	ECR RATE BASE - ALL PLANS (STAT ONLY)
951004	ECR COST OF CAPITAL - ALL 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)
951202	GLT DEPRECIATION SAVINGS (STAT ONLY)
951203	GLT COST OF CAPITAL (STAT ONLY)
951204	CHANGE IN YTD AVERAGE GLT RATE BASE, APPLIED TO ALL MONTHS (STAT ONLY)
999999	GL TO PA INTERFACE

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(n)
Sponsoring Witness: Kent W. Blake

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 - Louisville Gas and Electric Company

November 2013

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	117,997,511	115,931,902	2,065,609
Cost of Revenues	(54,542,460)	(53,698,872)	(843,588)
Electric Margin	46,798,446	48,078,659	(1,280,213)
Gas Margin	16,656,606	14,154,371	2,502,234
O&M	(24,696,692)	(28,356,072)	3,659,380
Other Income & Expenses	(214,540)	(144,917)	(69,622)
Depreciation	(12,373,362)	(12,677,507)	304,145
Property tax	(2,052,474)	(1,959,093)	(93,381)
Interest	(3,753,222)	(4,473,069)	719,847
Income Tax	(7,732,918)	(5,222,149)	(2,510,769)
Net Income from Ongoing Operations	**12,631,843**	**9,400,222**	**3,231,622**
Special Items	0	0	0
Net Income	**12,631,843**	**9,400,222**	**3,231,622**

Net Income Continuing Operations - Louisville Gas and Electric Company

December 2013

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	144,138,933	146,705,504	(2,566,570)
Cost of Revenues	(70,860,276)	(71,873,014)	1,012,738
Electric Margin	52,953,546	54,386,639	(1,433,093)
Gas Margin	20,325,111	20,445,851	(120,739)
O&M	(27,050,194)	(28,013,763)	963,569
Other Income & Expenses	(549,567)	(161,531)	(388,036)
Depreciation	(12,388,072)	(12,810,712)	422,640
Property tax	(1,896,639)	(1,959,093)	62,454
Interest	2,528,011	(4,333,884)	6,861,895
Income Tax	(12,535,024)	(10,473,229)	(2,061,795)
Net Income from Ongoing Operations	**21,387,172**	**17,080,277**	**4,306,894**
Special Items	0	0	0
Net Income	**21,387,172**	**17,080,277**	**4,306,894**

Net Income Continuing Operations - Louisville Gas and Electric Company

January 2014

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	186,832,227	150,113,779	36,718,449
Cost of Revenues	(98,902,626)	(76,142,186)	(22,760,440)
Electric Margin	61,693,485	51,399,432	10,294,054
Gas Margin	26,236,116	22,572,161	3,663,955
O&M	(26,497,946)	(26,549,014)	51,068
Other Income & Expenses	(437,058)	(338,577)	(98,481)
Depreciation	(12,465,951)	(12,650,402)	184,451
Property tax	(2,139,024)	(1,772,807)	(366,217)
Interest	(4,105,105)	(4,201,641)	96,536
Income Tax	(16,299,611)	(10,823,529)	(5,476,083)
Net Income from Ongoing Operations	**25,984,906**	**17,635,623**	**8,349,284**
Special Items	0	0	0
Net Income	**25,984,906**	**17,635,623**	**8,349,284**

Net Income Continuing Operations - Louisville Gas and Electric Company

February 2014

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	155,650,961	138,532,270	17,118,691
Cost of Revenues	(85,210,122)	(70,423,757)	(14,786,365)
Electric Margin	53,185,616	48,137,800	5,047,815
Gas Margin	17,255,224	19,970,713	(2,715,489)
O&M	(27,492,054)	(26,173,655)	(1,318,399)
Other Income & Expenses	(275,320)	(175,269)	(100,051)
Depreciation	(12,530,139)	(12,670,371)	140,231
Property tax	(2,141,510)	(1,772,807)	(368,703)
Interest	(4,061,645)	(4,196,813)	135,168
Income Tax	(9,163,661)	(8,746,443)	(417,218)
Net Income from Ongoing Operations	**14,776,511**	**14,373,156**	**403,354**
Special Items	0	0	0
Net Income	**14,776,511**	**14,373,156**	**403,354**

Net Income Continuing Operations - Louisville Gas and Electric Company

March 2014

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	137,386,469	125,002,853	12,383,616
Cost of Revenues	(70,811,520)	(60,551,507)	(10,260,013)
Electric Margin	50,971,466	48,736,811	2,234,655
Gas Margin	15,603,483	15,714,535	(111,052)
O&M	(33,023,530)	(29,447,100)	(3,576,430)
Other Income & Expenses	(171,907)	(296,419)	124,512
Depreciation	(12,548,688)	(12,683,575)	134,887
Property tax	(2,139,552)	(1,772,807)	(366,745)
Interest	(4,011,797)	(4,194,320)	182,523
Income Tax	(4,099,109)	(5,405,413)	1,306,304
Net Income from Ongoing Operations	**10,580,367**	**10,651,713**	**(71,346)**
Special Items	0	0	0
Net Income	**10,580,367**	**10,651,713**	**(71,346)**

Net Income Continuing Operations - Louisville Gas and Electric Company

April 2014

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	109,832,080	102,673,510	7,158,571
Cost of Revenues	(52,237,491)	(45,367,350)	(6,870,141)
Electric Margin	46,552,810	46,486,997	65,812
Gas Margin	11,041,779	10,819,162	222,617
O&M	(31,036,543)	(31,255,814)	219,271
Other Income & Expenses	(697,964)	(655,454)	(42,509)
Depreciation	(12,571,774)	(12,703,611)	131,837
Property tax	(1,940,792)	(1,772,807)	(167,985)
Interest	(4,069,479)	(4,194,617)	125,137
Income Tax	(2,682,090)	(2,368,499)	(313,591)
Net Income from Ongoing Operations	**4,595,947**	**4,355,358**	**240,589**
Special Items	0	0	0
Net Income	**4,595,947**	**4,355,358**	**240,589**

Net Income Continuing Operations - Louisville Gas and Electric Company

May 2014

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	114,672,042	107,330,075	7,341,967
Cost of Revenues	(49,129,980)	(47,498,321)	(1,631,660)
Electric Margin	56,567,195	50,633,433	5,933,762
Gas Margin	8,974,867	9,198,322	(223,454)
O&M	(25,748,510)	(29,485,152)	3,736,642
Other Income & Expenses	(292,014)	(157,356)	(134,657)
Depreciation	(12,594,942)	(12,728,125)	133,183
Property tax	(2,088,813)	(1,772,807)	(316,006)
Interest	(4,109,271)	(4,204,960)	95,689
Income Tax	(7,906,545)	(4,219,944)	(3,686,602)
Net Income from Ongoing Operations	**12,801,967**	**7,263,411**	**5,538,556**
Special Items	0	0	0
Net Income	**12,801,967**	**7,263,411**	**5,538,556**

Net Income Continuing Operations - Louisville Gas and Electric Company

June 2014

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	120,998,880	118,030,453	2,968,427
Cost of Revenues	(49,059,615)	(49,863,230)	803,615
Electric Margin	63,432,072	59,832,879	3,599,193
Gas Margin	8,507,193	8,334,344	172,849
O&M	(24,036,511)	(28,795,161)	4,758,650
Other Income & Expenses	(157,342)	(87,919)	(69,423)
Depreciation	(12,699,426)	(12,752,642)	53,216
Property tax	(2,086,502)	(1,772,807)	(313,695)
Interest	(4,017,145)	(4,220,454)	203,309
Income Tax	(10,698,968)	(7,148,566)	(3,550,401)
Net Income from Ongoing Operations	**18,243,372**	**13,389,674**	**4,853,698**
Special Items	0	0	0
Net Income	**18,243,372**	**13,389,674**	**4,853,698**

Net Income Continuing Operations - Louisville Gas and Electric Company

July 2014

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	117,732,223	127,892,595	(10,160,372)
Cost of Revenues	(46,625,142)	(52,435,647)	5,810,505
Electric Margin	63,297,869	67,198,620	(3,900,751)
Gas Margin	7,809,212	8,258,328	(449,116)
O&M	(27,715,064)	(29,138,931)	1,423,867
Other Income & Expenses	(62,721)	(137,682)	74,961
Depreciation	(12,813,715)	(12,775,761)	(37,954)
Property tax	(2,122,182)	(1,776,668)	(345,514)
Interest	(4,095,755)	(4,229,422)	133,667
Income Tax	(9,302,717)	(10,410,929)	1,108,212
Net Income from Ongoing Operations	**14,994,926**	**16,987,554**	**(1,992,628)**
Special Items	0	0	0
Net Income	**14,994,926**	**16,987,554**	**(1,992,628)**

Net Income Continuing Operations - Louisville Gas and Electric Company

August 2014

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	122,210,342	128,913,007	(6,702,664)
Cost of Revenues	(47,398,626)	(53,814,175)	6,415,549
Electric Margin	66,428,163	66,788,018	(359,855)
Gas Margin	8,383,553	8,310,814	72,740
O&M	(25,977,853)	(28,126,284)	2,148,431
Other Income & Expenses	(297,488)	(191,408)	(106,080)
Depreciation	(12,848,713)	(12,791,992)	(56,721)
Property tax	(2,122,184)	(1,776,668)	(345,516)
Interest	(4,129,455)	(4,237,767)	108,312
Income Tax	(11,279,748)	(10,635,082)	(644,666)
Net Income from Ongoing Operations	**18,156,275**	**17,339,631**	**816,644**
Special Items	0	0	0
Net Income	**18,156,275**	**17,339,631**	**816,644**

Net Income Continuing Operations - Louisville Gas and Electric Company

September 2014

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	108,197,252	111,874,320	(3,677,068)
Cost of Revenues	(42,619,145)	(45,469,889)	2,850,745
Electric Margin	56,877,799	57,944,371	(1,066,571)
Gas Margin	8,700,308	8,460,060	240,248
O&M	(27,812,881)	(29,587,795)	1,774,914
Other Income & Expenses	(167,333)	(67,013)	(100,320)
Depreciation	(12,872,619)	(12,821,061)	(51,558)
Property tax	(2,122,161)	(1,776,668)	(345,493)
Interest	(4,080,687)	(4,244,057)	163,370
Income Tax	(6,574,028)	(6,125,339)	(448,689)
Net Income from Ongoing Operations	**11,948,399**	**11,782,497**	**165,902**
Special Items	0	0	0
Net Income	**11,948,399**	**11,782,497**	**165,902**

Net Income Continuing Operations - Louisville Gas and Electric Company

October 2014

Month To Date Actual VS Month To Date Budget

	MTD Actual	MTD Budget	Variance
Revenues	99,888,464	102,876,440	(2,987,976)
Cost of Revenues	(39,253,698)	(43,230,001)	3,976,303
Electric Margin	50,678,041	49,134,155	1,543,886
Gas Margin	9,956,726	10,512,285	(555,560)
O&M	(28,320,363)	(32,845,167)	4,524,804
Other Income & Expenses	(204,182)	(147,814)	(56,368)
Depreciation	(12,890,758)	(12,849,522)	(41,237)
Property tax	(2,130,204)	(1,776,668)	(353,536)
Interest	(4,162,862)	(4,256,826)	93,964
Income Tax	(4,879,302)	(2,775,621)	(2,103,681)
Net Income from Ongoing Operations	**8,047,094**	**4,994,822**	**3,052,272**
Special Items	0	0	0
Net Income	**8,047,094**	**4,994,822**	**3,052,272**

Louisville Gas and Electric Company
Case No. 2014-00372
Forecasted Test Period Filing Requirements
(Forecast Test Year 12ME 6/30/16; Base Period 12ME 2/28/15)

Filing Requirement
807 KAR 5:001 Section 16(7)(o)
Sponsoring Witness: Kent W. Blake

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 Company has only one monthly performance report used for management reporting to the CEO and executive officers that address budget variances. Although the performance report contains separate analyses of gas and electric margins, no separate income statement, balance sheet or statement of cash flows are presented for gas versus electric operations, or KU versus LG&E, and decisions are based on the overall utility operations of LG&E and KU.

See attached for the monthly reports for:

- March 2013 through February 2014 which are the twelve months prior to the base period.
- Each month of the base period. Reports for March 2014 through October 2014 are presently available. LG&E will provide these reports for the remaining periods requested in the upcoming months as they become available.

Performance Report

March 2013

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Kentucky Regulated Dashboard — March 2013

Operational Metrics	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.68	0.34	1.18	0.66	N/A	1.35
Employee lost-time incidents	0	0	0	0	N/A	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,924	2,778	8,761	8,963	34,925	35,128
Utility EFOR	8.1%	5.1%	9.7%	5.1%	N/A	5.1%
Utility EAF	75.5%	81.8%	80.9%	88.4%	N/A	87.08%
Combined SAIFI	0.04	0.06	0.11	0.12	N/A	1.22
Combined SAIDI (minutes)	3.78	5.52	11.65	10.46	N/A	110
GwH Sales						
Residential	991	906	3,088	3,026	10,974	10,912
Commercial	646	616	1,897	1,893	8,067	8,063
Industrial	809	769	2,333	2,314	9,910	9,891
Municipals	161	151	485	458	1,971	1,944
Other	231	224	681	685	2,897	2,901
Off-System Sales	11	55	90	245	311	465
Total	2,849	2,722	8,575	8,621	34,130	34,175
Weather-Normalized Sales Growth(1)			**Actual**	**W-N**	**Actual**	**W-N**
Residential			4.4%	1.4%	5.5%	2.5%
Commercial			0.6%	-0.1%	0.4%	-0.1%
Industrial			0.1%	0.1%	4.4%	4.5%
Other(2)			0.0%	-0.4%	-1.1%	-1.4%
Total			1.6%	0.4%	3.0%	1.8%

Variance Explanations

- The generation fleet's EAF and EFOR are unfavorable to budget due to temperature and balance issues on Ghent 4 ID fan bearing and a turbine bearing failure and air heater pluggage on Trimble County 2.
- SAIDI is unfavorable YTD to budget due to a higher number of minor storms that occurred across Kentucky during January.
- Higher margins driven by higher retail volumes, as March heating degree days were 30% above normal.
- Capital spend YTD was $65m lower than budget due mainly to revised schedules for Mill Creek and Ghent environmental air work ($33m) expected to reverse by the end of 2013. Temporary differences on other environmental projects ($11m) and delayed spending on major Transmission and Distribution projects ($29m) are expected to reverse by year end and were partially offset by increased spend on Cane Run 7 ($10m).
- Capital spend full year is projected to be $18m lower than budget due mainly to delay in the Trimble County landfill to 2015 ($12m).

Significant Future Events

- In addition to the construction of Cane Run Unit 7, LG&E and KU continue to evaluate responses received from their request for proposals for up to 700 MW of capacity beginning as early as 2015. Initial assessments are expected to be completed in the second quarter.

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE(3)	11.0%	9.0%	11.9%	11.8%	9.6%	9.6%
Electric Margins	$134	$128	$400	$403	$1,625	$1,638
Gas Margins	$17	$16	$58	$58	$157	$156

Capital Expenditures ($ millions)	Actual	Budget	Actual	Budget	Forecast	Budget
New Generation	$17	$21	$63	$53	$308	$310
ECR	43	46	112	156	644	655
Generation	8	9	17	17	114	117
Transmission	6	11	12	29	108	107
Electric Distribution	9	13	26	35	150	152
Gas Distribution	3	6	9	12	74	77
Customer Services	1	1	3	3	16	13
IT and Other	1	4	7	9	38	39
Total	$88	$111	$249	$314	$1,452	$1,470

O&M ($ millions)(4)	Actual	Budget	Actual	Budget	Forecast	Budget
Operations	$36	$39	$104	$108	$459	$463
Administrative	8	8	22	22	92	94
Finance and Accounting	2	2	4	5	19	19
Corp Burdens & Other Charges	15	14	42	37	149	146
Total	$61	$62	$173	$171	$719	$721

Head Count	Actual	Budget	Actual	Budget	Forecast	Budget
Full-time Employees	3,314	3,402	3,314	3,402	3,435	3,435

Other Metrics	Actual	PY	Actual	PY	Forecast	
Environmental Events	2	0	3	0	N/A	
NERC Possible Violations	0	0	0	5	N/A	

Major Developments

- In Louisville and Lexington, March 2013 ranked as the coldest and the second coldest, respectively, in the last 20 years with heating degree days approximately 30% above normal.
- Old Dominion Power Company (KU’s operational unit in Virginia) filed an application with the Virginia State Corporation Commission to increase its rates to recover costs associated with improving service and reliability. The filing includes a $6.5 million or 9.6 percent rate increase premised upon a 10.8 percent return on equity. The rates will become effective January 1, 2014, pending approval from the Commission.
- The Kentucky Division of Waste Management notified LG&E of its intent to deny LG&E’s Special Waste Landfill permit application for the Trimble County CCR landfill. The denial was based solely on its interpretation of the Cave Protection Act and not on special waste regulations. LG&E plans to move forward with a new permit application for the next lowest cost alternate location which is also on existing plant property. The revised footprint will avoid any impact to the karst feature that was under review.
- For the third consecutive year, LG&E and KU have been awarded the ENERGY STAR Partner of the Year - Sustained Excellence Award by the EPA. The award recognizes LG&E and KU’s continued leadership in protecting the environment through superior energy efficiency. LG&E and KU, ENERGY STAR partners since 2009, have helped spur the construction of more than 2,800 ENERGY STAR-certified homes within their service territories. These accomplishments were recognized at an awards ceremony in Washington, D.C.

(1) Full year percentages represent a trailing twelve months.

(2) "Other" is typically comprised of the public authority customer class and KU's 12 full-requirements wholesale municipal customers.

(3) Excludes goodwill and other purchase accounting adjustments.

(4) Net of cost recovery mechanisms.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget March 2013

($ Millions)

	MTD				YTD			
	Actual	Budget	Variance	Comments	Actual	Budget	Variance	Comments
Revenues:								
Electric Revenues	$ 225	$ 214	$ 11	Retail volumes higher than budget by 6%.	$ 672	$ 676	$ (4)	Unfavorable demand volumes partially offset by higher retail volumes than budget.
Gas Revenues	40	35	5	Increase in gas supply revenues, offset by increased expenses below.	130	132	(3)	
Total Revenues	264	248	16		802	808	(7)	
Cost of Sales:								
Fuel Electric Costs	78	72	(6)	Increased energy volumes due to favorable weather conditions. Offset by favorable electric revenues.	232	232	(0)	
Gas Supply Expenses	23	19	(4)		72	75	3	
Purchased Power	5	6	1		15	15	(0)	
Other Electric Cost	8	8	1		24	26	1	
Total Cost of Sales	114	105	(9)		343	347	4	
Gross Margin:								
Electric Margin	134	128	6		400	403	(3)	
Gas Margin	17	16	1		58	58	(0)	
Total Gross Margin	151	144	7	Higher margins driven by higher retail volumes, as March heating degree days were 30% above normal	458	461	(3)	
Operating Expenses:								
O&M	61	62	1		173	171	(2)	
Depreciation & Amortization	27	28	1		81	84	2	
Taxes, Other than Income	4	4	0		12	12	0	
Total Operating Expenses	92	94	2		266	267	0	
Equity in earnings	-	(0)	0		-	(0)	0	
Other income	(2)	(1)	(1)		(3)	(3)	0	
EBIT	57	49	8		189	191	(2)	
Interest Expense	12	12	0		37	37	0	
Income from Ongoing Operations before income taxes	45	36	8		152	154	(2)	
Income Tax Expense	17	13	(3)		57	58	1	
Net Income (loss) from ongoing operations	**28**	**23**	**5**		**95**	**96**	**(1)**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	1	(0)	1		0	(0)	1	
Net Income (loss)	$ 29	$ 23	$ 6		$ 96	$ 96	$ 1	
KY Regulated Financing Costs	(4)	(3)	(1)		(11)	(10)	(1)	
KY Regulated Net Income	$ 24	$ 19	$ 5		$ 84	$ 86	$ (2)	
Earnings Per Share	$ 0.04	$ 0.03	$ 0.01		$ 0.14	$ 0.15	$ (0.00)	

Income Statement: Forecast vs. Budget — March 2013

($ Millions)

	Full Year			
	Q1 Forecast	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 2,732	$ 2,753	$ (21)	Lower retail and wholesale demand volumes and lower ECR returns.
Gas Revenues	311	313	(2)	
Total Revenues	3,043	3,065	(23)	
Cost of Sales:				
Fuel Electric Costs	928	928	(0)	
Gas Supply Expenses	154	157	3	
Purchased Power	68	67	(1)	
Other Electric Cost	111	119	8	
Total Cost of Sales	1,261	1,271	10	Lower retail and wholesale demand volumes and lower ECR costs, offset by unfavorable revenues above.
Gross Margin:				
Electric Margin	1,625	1,638	(13)	YTD margin shortfall of $3m, lower ECR of $3m due to delayed capital spend, and lower demand projections of $7m.
Gas Margin	157	156	1	
Total Gross Margin	1,782	1,794	(12)	
Operating Expenses:				
O&M	719	721	2	
Depreciation & Amortization	329	338	8	Revised estimates based on delayed capital spend in 2012 and revised in-service dates for capital projects in 2013.
Taxes, Other than Income	48	48	(0)	
Total Operating Expenses	1,097	1,107	10	
Equity in earnings	0	(1)	1	
Other income	(8)	(8)	1	
EBIT	677	677	(0)	
Interest Expense	154	154	(1)	
Income from Ongoing Operations before income taxes	523	524	(1)	
Income Tax Expense	195	196	1	
Net Income (loss) from ongoing operations	**328**	**328**	**(0)**	
Non Operating Income	0	-	0	
Discontinued Operations	(1)	(1)	1	
Net Income (loss)	$ 327	$ 326	$ 1	
KY Regulated Financing Costs	(37)	(37)	-	
KY Regulated Net Income	$ 291	$ 290	$ 1	
Earnings Per Share	$ 0.47	$ 0.47	$ -	

Electric Gross Margin March 2013

($ Millions)

	MTD						YTD					
	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance
Base Electric Margin:						$ 6 🟢						$ (6) ♦
Energy Volumes (a)	2,838,348	2,666,715	171,633	$ 29.85	$ 6		8,484,975	8,376,066	108,909	$ 29.50	$ 3	
Energy Prices (a)					3						1	
Customer Charges (Avg. Customers)	935,726	943,486	(7,760)		-		935,711	943,448	(7,737)		1	
Demand Charges (b)					(2)						(11)	
ECR:						(1) ♦						(2) ♦
Average Rate Base	$ 565	$ 646	$ (81)	10.44%	$ (0.6)		$ 531	$ 595	$ (64)	10.44%	$ (1.5)	
Cost of Capital	10.29%	10.44%	-0.15%	$ 565	(0.1)		10.37%	10.44%	-0.07%	$ 531	(0.1)	
Jurisdictional Factor	88.47%	87.81%	0.66%	$ 565	-		87.81%	87.24%	0.58%	$ 531	0.1	
Other					(0.1)						(0.6)	
DSM:						- 🟢						1 🟢
Program Expense (Revenue Net of Expense)	$ -	$ (0.2)			$ 0.2		$ -	$ (0.7)			$ 0.7	
Lost Sales	1.1	1.0			0.1		3.5	3.0			0.5	
Incentive	0.1	0.1			-		0.3	0.2			0.1	
Balancing Adjustment	(0.3)	-			(0.3)		(0.1)	-			(0.1)	
Net Fuel Recovery	$ 0.2	$ (0.8)				1 🟢	$ 1	$ (2)				4 🟢
Purchase Power Demand						- 🟢						1 🟢
Transmission						- 🟢						0 🟢
Other						- 🟢						(1) ♦
Retail Margin Variance						6 🟢						(3) ♦
Off-System Margin Variance						- 🟢						(0) ♦
Electric Margin Variance						$ 6 🟢						$ (3) ♦

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 48	990,809	$ 48.24	$ 44	906,203	$ 48.12	$ 4 🟢	$ 4 🟢	$ 0 🟢
Commercial	21	646,403	32.40	20	615,792	32.69	1 🟢	1 🟢	(0) ♦
Industrial	9	808,859	11.51	7	769,357	8.80	2 🟢	0 🟢	2 🟢
Municipals	1	161,225	4.68	1	151,498	4.69	- 🟢	- 🟢	- 🟢
Other	6	231,052	25.64	5	223,865	23.77	1 🟢	0 🟢	0 🟢
Native Load Total	**$ 85**	**2,838,348**	**$ 29.85**	**$ 77**	**2,666,715**	**$ 28.70**	**$ 8** 🟢	**$ 6** 🟢	**$ 3** 🟢

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 149	3,088,469	$ 48.09	$ 145	3,026,024	$ 48.03	$ 4 🟢	$ 3 🟢	$ - 🟢
Commercial	62	1,897,185	32.69	62	1,892,979	32.81	- 🟢	- 🟢	- 🟢
Industrial	22	2,333,089	9.51	20	2,314,033	8.82	2 🟢	- 🟢	2 🟢
Municipals	2	485,298	4.68	2	458,407	4.69	- 🟢	- 🟢	- 🟢
Other	15	680,933	22.42	16	684,623	23.79	(1) ♦	- 🟢	(1) ♦
Native Load Total	**$ 250**	**8,484,975**	**$ 29.50**	**$ 246**	**8,376,066**	**$ 29.40**	**$ 5** 🟢	**$ 3** 🟢	**$ 1** 🟢

(b) Demand Analysis (net of base ECR revenue):	MTD			YTD		
$mil	Act	Bud	Variance	Act	Bud	Variance
Commercial	12	12	(0)	35	38	(4)
Industrial	15	16	(1)	45	50	(5)
Municipals	4	4	(1)	11	13	(2)
Other	5	5	(0)	14	14	(1)
Native Load Total	**35**	**37**	**(2)**	**105**	**115**	**(11)**

Weather Statistics	MTD			YTD		
	Act	+/- Bud		Act	+/- Bud	
Heating Degree Days - Louisville	763	194	34%	2,398	132	6%
Heating Degree Days - Lexington	783	158	25%	2,515	99	4%
Cooling Degree Days - Louisville	0	(5)	-100%	0	(5)	-100%
Cooling Degree Days - Lexington	0	(3)	-100%	0	(3)	-100%

Gas Gross Margin

March 2013

($ Millions)

	MTD					YTD				
	Actual	Budget	Subtotal	Margin Variance		Actual	Budget	Subtotal	Margin Variance	
Gas Base Service Charge	**$ 5**	**$ 5**		**$ -**	🟢	**$ 15**	**$ 15**		**$ -**	🟢
Gas Supply Costs										
Gas Supply Costs	(23)	(18)	$ (5)			(71)	(73)	$ 2		
GSC Revenue	23	18	5			71	73	(2)		
Net Gas Supply Costs				**-**	🟢				**-**	🟢
Retail Gas (a)	**13**	**10**		**3**	🟢	**42**	**40**		**2**	🟢
Wholesale Gas (a)	**-**	**-**		**-**	🟢	**-**	**-**		**-**	🟢
DSM	**-**	**-**		**-**	🟢	**-**	**-**		**-**	🟢
GLT	**-**	**-**		**-**	🟢	**1**	**1**		**-**	🟢
WNA	**(2)**	**-**		**(2)**	♦	**(1)**	**-**		**(1)**	♦
Other Margin	**-**	**-**		**-**	🟢	**-**	**1**		**(1)**	♦
Gas Margin Variance				**$ 1**	🟢				**$ -**	🟢

(a) Retail and wholesale gas sales - excludes GSC

	MTD											
	Actual			Budget			Variance					
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil		Volume $mil		Price $mil	
Residential	$ 9	3,251,265	$ 2.64	$ 7	2,543,834	$ 2.58	$ 2	🟢	$ 2	🟢	$ -	🟢
Commercial	3	1,338,648	2.09	2	1,046,205	2.05	1	🟢	1	🟢	-	🟢
Industrial	-	134,668	1.83	-	96,079	1.86	-	🟢	-	🟢	-	🟢
Public Authority	1	222,681	2.05	-	195,281	1.98	1	🟢	-	🟢	-	🟢
Transportation	1	1,287,559	0.77	1	1,167,751	0.45	-	🟢	-	🟢	-	🟢
Ultimate Consumer	$ 13	6,234,821	$ 2.10	$ 10	5,049,150	$ 1.94	$ 3	🟢	$ 3	🟢	$ 1	🟢

	YTD											
	Actual			Budget			Variance					
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil		Volume $mil		Price $mil	
Residential	$ 28	10,410,659	$ 2.64	$ 27	10,564,332	$ 2.57	$ 1	🟢	$ -	🟢	$ 1	🟢
Commercial	9	4,292,470	2.10	9	4,333,042	2.05	-	🟢	-	🟢	-	🟢
Industrial	1	400,463	1.87	1	347,779	1.87	-	🟢	-	🟢	-	🟢
Public Authority	2	781,043	2.05	2	789,686	1.99	-	🟢	-	🟢	-	🟢
Transportation	3	3,915,090	0.76	2	4,045,708	0.46	1	🟢	-	🟢	1	🟢
Ultimate Consumer	$ 42	19,799,725	$ 2.11	$ 40	20,080,547	$ 2.00	$ 2	🟢	$ (1)	♦	$ 2	🟢

O&M March 2013

($ Millions)

	MTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 20	$ 20	$ (0)	$ -	$ (0)	$ (1)	$ 1	$ -	$ -	$ -
Project Engineering	0	0	-	-	-	-	-	-	-	-
Transmission	2	3	1	-	(0)	-	1	-	-	(0)
Energy Supply and Analysis	1	1	-	-	-	-	-	-	-	-
Electric Distribution	5	6	(0)	-	(0)	-	-	-	-	-
Gas Distribution	2	2	-	-	-	-	-	-	-	-
Customer Services	6	7	2	-	-	-	-	-	1	1
Chief Operations Officer	**36**	**39**	**3**	**-**	**(0)**	**(1)**	**2**	**-**	**1**	**1**
Information Technology	4	4	-	-	-	-	-	-	-	-
General Counsel	3	3	-	-	-	-	-	-	-	-
Human Resources	1	1	0	-	0	-	-	-	-	-
Supply Chain	0	0	-	-	-	-	-	-	-	-
Chief Administrative Officer	**8**	**8**	**0**	**-**	**0**	**-**	**-**	**-**	**-**	**-**
Chief Financial Officer	**2**	**2**	**0**	**-**	**0**	**-**	**-**	**-**	**-**	**-**
Corporate	**15**	**14**	**(2)**	**(6)**	**-**	**-**	**-**	**-**	**1**	**3**
O&M Total MTD	**$ 61**	**$ 62**	**$ 1**	**$ (6)**	**$ (0)**	**$ (1)**	**$ 2**	**$ -**	**$ 2**	**$ 4**

	YTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 53	$ 51	$ (2)	$ -	$ 2	$ (1)	$ (1)	$ (2)	$ -	$ -
Project Engineering	0	0	-	-	-	-	-	-	-	-
Transmission	7	7	1	-	(0)	-	-	-	-	1
Energy Supply and Analysis	2	3	-	-	-	-	-	-	-	-
Electric Distribution	16	17	1	-	(0)	-	-	-	-	1
Gas Distribution	8	7	-	-	-	-	-	-	-	-
Customer Services	18	22	4	-	1	-	1	-	2	-
Chief Operations Officer	**104**	**108**	**4**	**-**	**3**	**(1)**	**-**	**(2)**	**2**	**2**
Information Technology	12	12	-	-	-	-	-	-	-	-
General Counsel	7	7	-	-	-	-	-	-	-	-
Human Resources	1	2	0	-	0	-	-	-	-	-
Supply Chain	1	1	-	-	-	-	-	-	-	-
Chief Administrative Officer	**22**	**22**	**0**	**-**	**0**	**-**	**-**	**-**	**-**	**-**
Chief Financial Officer	**4**	**5**	**0**	**-**	**0**	**-**	**-**	**-**	**-**	**-**
Corporate (a)	**42**	**37**	**(6)**	**(7)**	**-**	**-**	**1**	**1**	**1**	**(2)**
O&M Total YTD	**$ 173**	**$ 171**	**$ (2)**	**$ (7)**	**$ 3**	**$ (1)**	**$ 1**	**$ (1)**	**$ 3**	**$ -**

(a) Variance due mainly to $7m of jurisdictionalized pension regulatory asset write-off, partially offset by $2m of spare parts regulatory liability write-off.

	Full Year			Variances						
	Forecast	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 227	$ 227	$ 1	$ -	$ 2	$ (1)	$ (1)	$ (1)	$ -	$ 2
Project Engineering	1	1	-	-	-	-	-	-	-	-
Transmission	29	29	(0)	-	(0)	-	1	(1)	-	-
Energy Supply and Analysis	10	11	1	-	1	-	-	-	-	-
Electric Distribution	69	70	0	-	(1)	-	1	-	-	-
Gas Distribution	35	34	(1)	-	-	-	-	-	-	(1)
Customer Services	89	91	2	-	1	-	2	-	2	(3)
Chief Operations Officer	**459**	**463**	**3**	**-**	**3**	**(1)**	**3**	**(2)**	**2**	**(2)**
Information Technology	49	49	-	-	-	-	-	-	-	-
General Counsel	33	34	1	-	-	-	1	-	-	-
Human Resources	7	7	(0)	-	1	-	-	-	-	(1)
Supply Chain	3	3	-	-	-	-	-	-	-	-
Chief Administrative Officer	**92**	**94**	**1**	**-**	**1**	**-**	**1**	**-**	**-**	**(1)**
Chief Financial Officer	**19**	**19**	**0**	**-**	**0**	**-**	**-**	**-**	**-**	**-**
Corporate	**149**	**146**	**(3)**	**(5)**	**-**	**-**	**1**	**(1)**	**1**	**1**
O&M Total Full Year	**$ 719**	**$ 721**	**$ 1**	**$ (5)**	**$ 4**	**$ (1)**	**$ 5**	**$ (3)**	**$ 3**	**$ (2)**

Financing Activities

March 2013

($ Millions)

Balance Sheet	**MTD Actual**	**MTD Budget**	**MTD Variance**	**YTD Actual**	**YTD Budget**	**YTD Variance**	**Full Year Forecast**	**Full Year Budget**	**Full Year Variance**
PCB									
Beg Bal	$ 932.0	$ 932.0	$ -	$ 932.0	$ 932.0	$ 0.0	$ 932.0	$ 932.0	$ -
End Bal	931.9	931.9	-	931.9	931.9	-	931.7	931.7	-
Ave Bal	**$ 932.0**	**$ 932.0**	**$ -**	**$ 932.0**	**$ 932.0**	**$ (0.0)**	**$ 931.8**	**$ 931.8**	**$ -**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.2**	**$ 2.6**	**$ 3.4**	**$ 0.9**	**$ 12.7**	**$ 13.6**	**$ 0.9**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.09%**	**1.47%**	**0.37%**	**1.37%**	**1.46%**	**0.09%**
FMB/Sr Nts									
Beg Bal	$ 3,143.0	$ 3,143.0	$ (0.0)	$ 3,142.8	$ 3,142.8	$ 0.0	$ 3,142.8	$ 3,142.8	$ 0.0
End Bal	3,143.2	3,143.2	(0.0)	3,143.2	3,143.2	(0.0)	3,694.4	3,694.4	(0.0)
Ave Bal	**$ 3,143.1**	**$ 3,143.1**	**$ (0.0)**	**$ 3,143.0**	**$ 3,143.0**	**$ 0.1**	**$ 3,235.3**	**$ 3,235.3**	**$ (0.0)**
Interest Exp	**$ 9.6**	**$ 9.6**	**$ 0.0**	**$ 28.7**	**$ 28.7**	**$ (0.0)**	**$ 120.2**	**$ 120.2**	**$ (0.0)**
Rate	**0.00%**	**0.00%**	**0.00%**	**3.65%**	**3.65%**	**0.00%**	**3.72%**	**3.72%**	**0.00%**
Short-term Debt									
Beg Bal	$ 309.2	$ 271.1	$ (38.1)	$ 149.7	$ 149.7	$ (0.0)	$ 149.7	$ 149.7	$ (0.0)
End Bal	269.8	224.5	(45.3)	269.8	224.5	(45.3)	210.5	176.3	(34.2)
Ave Bal	**$ 289.5**	**$ 247.8**	**$ (41.7)**	**$ 209.7**	**$ 254.1**	**$ 44.3**	**$ 372.4**	**$ 359.1**	**$ (13.3)**
Interest Exp	**$ 0.2**	**$ 0.2**	**$ (0.0)**	**$ 573.8**	**$ 496.5**	**$ (77.2)**	**$ 2.9**	**$ 1.2**	**$ (1.7)**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.09%**	**0.78%**	**-0.31%**			
Total End Bal	**$ 4,344.9**	**$ 4,299.6**	**$ (45.3)**	**$ 4,344.9**	**$ 4,299.6**	**$ (45.3)**	**$ 4,836.6**	**$ 4,802.4**	**$ (34.2)**
Total Average Bal	**$ 4,364.6**	**$ 4,322.9**	**$ (41.7)**	**$ 4,284.7**	**$ 4,329.1**	**$ 44.4**	**$ 4,539.6**	**$ 4,526.3**	**$ (13.3)**
Total Expense Excl I/C	**$ 12.4**	**$ 12.5**	**$ 0.1**	**$ 37.0**	**$ 37.4**	**$ 0.4**	**$ 154.4**	**$ 153.8**	**$ (0.6)**
Rate	**3.66%**	**3.71%**	**0.05%**	**3.45%**	**3.46%**	**0.01%**	**3.40%**	**3.40%**	**0.00%**

Credit Facilities ($ Millions)	**Committed Capacity**	**Borrowed**	**Letters of Credit Issued**	**Unused Capacity**
LKE	$ 300	$ 85		$ 215
LG&E	500	70		430
KU	598	115	$ 198	285
TOTAL	$ 1,398	$ 270	$ 198	$ 930

Credit Metrics ($ Millions)	**YTD Actual**	**YTD +/- Bud**	**Full Year Forecast**	**Full Year +/- Bud**
FFO to Debt - LG&E	32.3%	-0.02	26.5%	+0.00
FFO to Debt - KU	26.7%	-0.02	23.6%	-0.02
Debt to EBITDA - LG&E (1)	2.85	-0.46	3.32	+0.01
Debt to EBITDA - KU (1)	3.87	+0.21	3.67	+0.00
Debt to Capitalization - LG&E (2)	44.4%	+0.01	47.0%	-0.00
Debt to Capitalization - KU (2)	46.2%	-0.00	47.0%	+0.00

(1) Actuals represent a trailing 12 months

(2) Excludes purchase accounting adjustments and corresponding goodwill of $996m

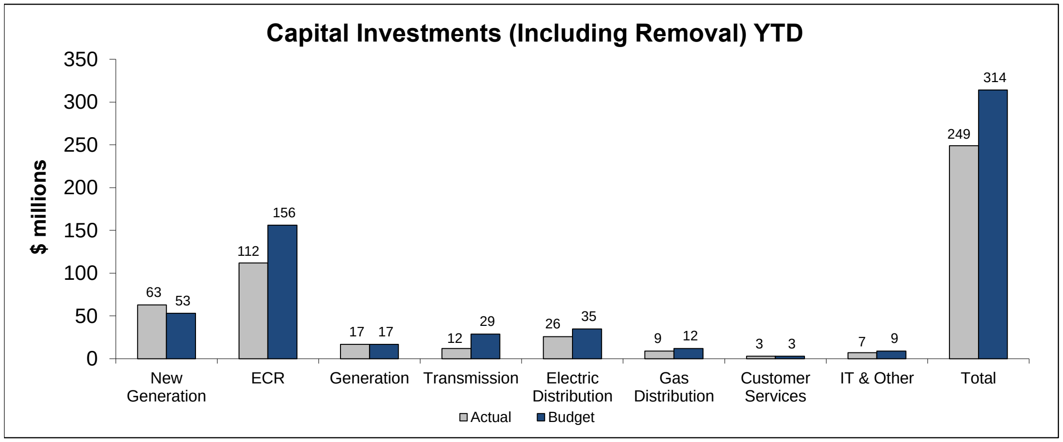
Balance Sheet

March 2013

($ Millions)

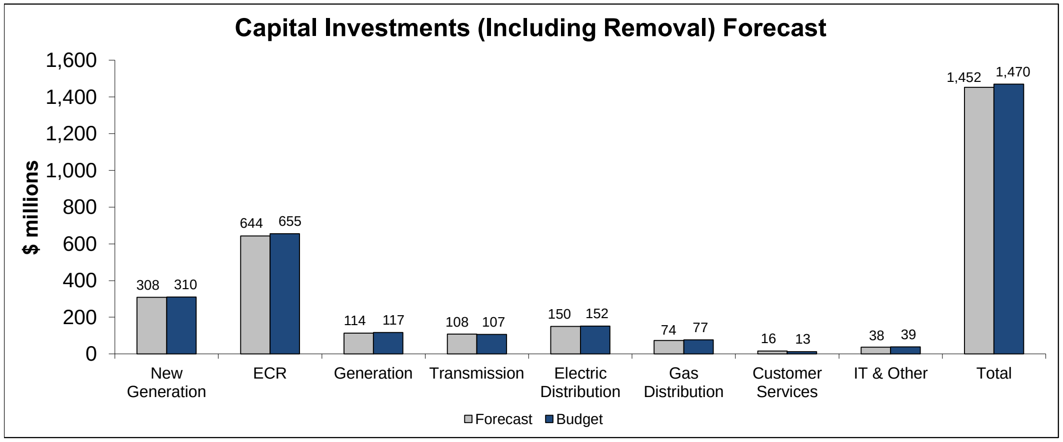
	YTD	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 52	$ 13	$ 39	See cash flow for details.
Accounts Receivable (Trade)	379	327	52	Tariff rate variance in receivable logic and extended due date granted in rate case.
Inventory	229	225	4	
Deferred Income Taxes	13	13	(1)	
Prepayments and other current assets	58	56	3	
Total Current Assets	730	634	97	
Property, Plant, and Equipment	8,479	8,543	(64)	See capital chart for details.
Intangible Assets	258	258	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets	635	641	(5)	
Goodwill	997	997	-	
Other Long-term Assets	103	106	(3)	
Total Assets	**$ 11,204**	**$ 11,180**	**$ 24**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 293	$ 251	$ 42	Primarily due to higher fuel volumes and higher capex accrual.
Accounts Payable - Affiliated Company	-	(0)	0	
Customer Deposits	49	48	1	
Derivative Liability	5	5	(0)	
Accrued Taxes	24	54	(30)	Tax payments made in actuals but not in budget.
Other Current Liabilities	131	132	(1)	
Total Current Liabilities	502	490	12	
Debt - Affiliated Company	-	-	-	
Debt	4,345	4,300	45	Issuance of short-term debt for non-utility expenses.
Total Debt	4,345	4,300	45	
Deferred Tax Liabilities	587	584	3	
Investment Tax Credit	138	137	0	
Accumulated Provision for Pension and Related Benefits	265	267	(2)	
Asset Retirement Obligation	127	127	0	
Regulatory Liabilities	1,007	1,007	(1)	
Derivative Liability	49	54	(4)	
Other Liabilities	233	240	(8)	
Total Deferred Credits and Other Liabilities	2,405	2,416	(11)	
Equity	3,952	3,974	(22)	
Total Liabilities and Equity	**$ 11,204**	**$ 11,180**	**$ 24**	

Capital Investments March 2013



Capital Investments (Including Removal) YTD

Capital was $65m lower than budget due mainly to revised schedules for Mill Creek and Ghent environmental air work ($33m) expected to reverse by the end of 2013. Temporary differences on other environmental projects ($11m) and delayed spending on major Transmission and Distribution projects ($29m) are expected to reverse by year end and were partially offset by increased spend on Cane Run 7 ($10m).



Capital Investments (Including Removal) Forecast

Capital is projected to be $18m lower than budget due mainly to delay in the Trimble County landfill to 2015 ($12m).

Cash Flow

March 2013

YTD	Actual	Budget	Variance	Comments
Net income	96	96	1	
Depreciation	83	87	-4	
Deferred tax expense	45	41	4	
Other Balance Sheet Movements	-111	-101	-10	
Funds From Operations	**114**	**124**	**-9**	
Changes in accounts receivables	-86	-34	-52	Tariff rate variance in receivable logic, extended due date granted in rate case and higher sales as March heating degree days were 30% above normal.
Changes in inventories	47	50	-3	
Changes in accounts payable	10	3	7	
Change in Working Capital	**-29**	**19**	**-48**	
Operating Cash flow	**85**	**142**	**-57**	
Capex	-271	-341	70	See Capex Charts for details.
Other Investing	4	0	4	
Loans to Affiliates	0	0	0	
Investing Cash flow	**-267**	**-341**	**74**	
Dividends	-4	0	-4	
Equity Infusion	75	93	-18	Lower capital spend.
Net Borrowings	120	75	45	Issuance of short-term debt for non-utility expenses.
Other	0	0	0	
Financing Cash flow	**191**	**168**	**41**	
Net increase (decrease) in cash	**9**	**-30**	**59**	

Full Year	FC	Budget	Variance	Comments
Net income	327	326	1	
Depreciation, amortization and impairments	349	356	-6	
Deferred tax expense	183	178	4	
Other Balance Sheet Movements	-216	-204	-12	
Funds From Operations	**644**	**656**	**-13**	
Changes in accounts receivables	-66	-35	-31	Tariff rate variance in receivable logic, extended due date granted in rate case and higher sales as March heating degree days were 30% above normal.
Changes in inventories	13	15	-3	
Changes in accounts payable	117	113	4	
Change in Working Capital	**64**	**94**	**-30**	
Operating Cash flow	**708**	**750**	**-42**	
Capex	-1,511	-1,576	65	Revised cash adjustment ($47m) and delay in Trimble County landfill to 2015 ($12m). See Capex Charts for details.
Other Investing	4	0	4	
Loans to Affiliates	0	0	0	
Investing Cash flow	**-1,507**	**-1,576**	**70**	
Dividends	-182	-157	-25	Higher dividends and lower equity infusions due to lower capital spend projected than budgeted.
Equity Infusion	338	374	-36	Higher dividends and lower equity infusions due to lower capital spend projected than budgeted.
Net Borrowings	611	577	34	Issuance of short-term debt for non-utility expenses.
Other	0	0	0	
Financing Cash flow	**766**	**794**	**9**	
Net increase (decrease) in cash	**-33**	**-33**	**36**	

Performance Report

April 2013

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Kentucky Regulated Dashboard

April 2013

Operational Metrics	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.23	1.27	1.19	0.80	N/A	1.35
Employee lost-time incidents	0	0	0	0	N/A	6

Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,430	2,461	11,191	11,424	34,925	35,128
Utility EFOR	9.0%	5.1%	9.5%	5.1%	N/A	5.1%
Utility EAF	63.7%	74.4%	76.8%	85.0%	N/A	87.08%
Combined SAIFI	0.09	0.11	0.26	0.30	N/A	1.22
Combined SAIDI (minutes)	6.82	9.91	23.59	27.04	N/A	110
GwH Sales						
Residential	649	691	3,738	3,717	10,974	10,912
Commercial	573	592	2,470	2,485	8,067	8,063
Industrial	792	763	3,125	3,077	9,910	9,891
Municipals	138	133	623	592	1,971	1,944
Other	215	217	895	902	2,897	2,901
Off-System Sales	14	17	105	261	311	465
Total	2,381	2,413	10,956	11,034	34,130	34,175
Weather-Normalized Sales Growth(1)			**W-N**			
Residential			2.27%			
Commercial			0.23%			
Industrial			4.45%			
Other(2)			-0.97%			
Total			1.92%			

Variance Explanations

- The generation fleet's EAF and EFOR are unfavorable to budget due to temperature and balance issues on Ghent 4 ID fan bearing, turbine bearing failure and air heater pluggage on Trimble County 2, hydrogen seal leak and damaged bearing on Mill Creek 4 and damaged boiler corner support hangers on Brown 3.
- Lower margins YTD primarily due to $12 million of lower electricity demand revenues.
- Capital was $88m lower than budget YTD due mainly to revised schedules for Mill Creek and Ghent environmental air work ($49m) expected to reverse by the end of 2013. Temporary differences on other environmental projects ($4m) and delayed spending on major Transmission and Distribution projects ($39m) are expected to reverse by year end and were partially offset by increased spend on Cane Run 7 ($8m).
- Capital is projected to be $18m lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.

Significant Future Events

- In addition to the construction of Cane Run Unit 7, LG&E and KU continue to evaluate responses received from their request for proposals for up to 700 MW of capacity beginning as early as 2015. Initial assessments are nearing completion with respondents to be notified during the second quarter.

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE(3)	3.4%	4.8%	9.7%	10.0%	9.6%	9.6%
Electric Margins	$108	$116	$509	$520	$1,625	$1,638
Gas Margins	$13	$11	$71	$69	$157	$156

Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$21	$23	$84	$76	$308	$310
ECR	41	50	153	206	644	655
Generation	8	8	26	24	114	117
Transmission	7	11	19	40	108	107
Electric Distribution	11	15	37	50	150	152
Gas Distribution	4	6	14	19	74	77
Customer Services	1	1	4	4	16	13
IT and Other	2	4	7	13	38	39
Total	$95	$118	$344	$432	$1,452	$1,470

O&M ($ millions)(4)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$45	$43	$149	$151	$459	$463
Administrative	$7	8	$29	$29	92	94
Finance and Accounting	$1	2	$5	$6	19	19
Corp Burdens & Other Charges	$12	12	$55	$49	149	146
Total	$65	$64	$238	$235	$719	$721

Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,326	3,409	3,326	3,409	3,435	3,435

Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	3	0	N/A	14
NERC Possible Violations(5)	3	0	3	5	N/A	29

Major Developments

- On April 18, LG&E and KU received its final audit report from SERC for the CIP audit conducted October 1-19, 2012. The SERC auditors indicated that the report's finding of 5 minor potential violations represented the fewest potential violations identified in a SERC CIP audit thus far. Importantly, the auditors were also extremely complimentary of LG&E/KU's preparedness, organization, and professionalism and the report itself described LG&E and KU as having "a very effective compliance program", which is the highest formal rating SERC gives.
- On April 22, LG&E celebrated the grand opening of a new one-of-a-kind beneficial use facility at Mill Creek. Company officials were joined by Senate Republican Leader Mitch McConnell and Senator Rand Paul; Commissioner of Agriculture James Comer; House Majority Floor Leader Rocky Adkins; and Charles Price, president and CEO of Charah, Inc. The Charah, Inc. SUL4R-PLUS® Product Manufacturing Facility is the first facility of its type and will recover approximately 300,000 tons of gypsum annually to create a unique sulfur product that will be sold to and distributed by agricultural companies. The facility is expected to create 20 new jobs when at full capacity by 2014.
- On April 27, LG&E and KU representatives met with KPSC staff for its quarterly update on major environmental projects as called for under the ECR Order approving these projects. That same Order had deferred decision on the installation of baghouses at Brown Units 1 and 2 until no sooner than the second half of 2013. The Company notified staff that it would not be pursuing this project as current analyses showed it was not in the economic interest of its customers. The Company noted that it did not, however, intend to retire these units at this time and is studying an additive product that may allow the units to meet environmental requirements for some time beyond 2015 with certain operational changes.
- On April 30, the Virginia State Corporation Commission issued an Order in KU's Virginia rate case that established a procedural schedule. A public evidentiary hearing is scheduled for October 1, 2013, with an Order expected by yearend and new rates effective January 1, 2014.

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(1) Percentages represent a trailing twelve months.

(2) "Other" is typically comprised of the public authority customer class and KU's 12 full-requirements wholesale municipal customers.

(3) Excludes goodwill and other purchase accounting adjustments.

(4) Net of cost recovery mechanisms.

(5) The NERC Possible Violation Issues for the current month are expected to be resolved through NERC's Find, Fix and Track ("FFT") process without financial penalty.

Income Statement: Actual vs. Budget and Forecast (Month) April 2013

($ Millions)

	MTD				MTD			
	Actual	**Budget**	**Variance**	**Comments**	**Actual**	**Q1 Forecast**	**Variance**	**Comments**
Revenues:								
Electric Revenues	$ 190	$ 195	$ (4)		$ 190	$ 194	$ (3)	
Gas Revenues	23	20	4		23	20	3	
Total Revenues	214	214	(1)		214	214	(0)	
Cost of Sales:								
Fuel Electric Costs	68	65	(4)		68	65	(4)	
Gas Supply Expenses	11	9	(2)		11	10	(1)	
Purchased Power	5	5	(0)		5	5	(0)	
Other Electric Cost	8	8	0		8	6	(2)	
Total Cost of Sales	93	87	(6)		93	86	(7)	
Gross Margin:								
Electric Margin	108	116	(8)		108	117	(9)	
Gas Margin	13	11	2		13	11	2	
Total Gross Margin	121	127	(6)	Primarily $2m of lower electricity demand revenues and $3m of timing variances.	121	128	(7)	Primarily $2m of lower electricity demand revenues and $3m of timing variances.
Operating Expenses:								
O&M	65	64	(1)		65	70	5	Favorable labor and burdens, uncollectible accounts, outside services and materials and supplies.
Depreciation & Amortization	27	28	0		27	27	(0)	
Taxes, Other than Income	4	4	0		4	4	0	
Total Operating Expenses	97	96	(0)		97	102	5	
Equity in earnings	-	(0)	0		-	0	(0)	
Other income	(1)	(1)	(0)		(1)	(1)	(0)	
EBIT	23	30	(7)		23	26	(2)	
Interest Expense	12	12	0		12	13	0	
Income from Ongoing Operations before income taxes	11	18	(7)		11	13	(2)	
Income Tax Expense	4	6	2		4	4	0	
Net Income (loss) from ongoing operations	**7**	**11**	**(4)**		**7**	**9**	**(2)**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	1	(0)	2		1	0	1	
Net Income (loss)	$ 8	$ 11	$ (3)		$ 8	$ 9	$ (1)	
KY Regulated Financing Costs	(3)	(3)	0		(3)	(3)	0	
KY Regulated Net Income	$ 5	$ 8	$ (3)		$ 5	$ 6	$ (0)	
Earnings Per Share	$ 0.01	$ 0.02	$ (0.00)		$ 0.01	$ 0.01	$ (0.00)	

Income Statement: Actual vs. Budget (YTD) and Forecast vs. Budget (Full Year)

April 2013

($ Millions)

	YTD				Full Year			
	Actual	Budget	Variance	Comments	Q1 Forecast	Budget	Variance	Comments
Revenues:								
Electric Revenues	$ 862	$ 871	$ (8)	Unfavorable demand volumes partially offset by higher retail volumes than budget.	$ 2,732	$ 2,753	$ (21)	Lower retail and wholesale demand volumes and lower ECR returns.
Gas Revenues	153	152	1		311	313	(2)	
Total Revenues	1,015	1,023	(7)		3,043	3,065	(23)	
Cost of Sales:								
Fuel Electric Costs	301	297	(4)		928	928	(0)	
Gas Supply Expenses	82	84	1		154	157	3	
Purchased Power	20	20	(0)		68	67	(1)	
Other Electric Cost	32	34	2		111	119	8	
Total Cost of Sales	436	434	(1)		1,261	1,271	10	Lower retail and wholesale demand volumes and lower ECR costs, offset by unfavorable revenues above.
Gross Margin:								
Electric Margin	509	520	(11)		1,625	1,638	(13)	YTD margin shortfall of $3m, lower ECR of $3m due to delayed capital spend, and lower demand projections of $7m.
Gas Margin	71	69	2		157	156	1	
Total Gross Margin	580	589	(9)	Primarily due to $12m of lower electricity demand revenues.	1,782	1,794	(12)	
Operating Expenses:								
O&M	238	235	(3)		719	721	2	
Depreciation & Amortization	109	112	3		329	338	8	Revised estimates based on delayed capital spend in 2012 and revised in-service dates for capital projects in 2013.
Taxes, Other than Income	16	16	0		48	48	(0)	
Total Operating Expenses	363	363	(0)		1,097	1,107	10	
Equity in earnings	-	(0)	0		0	(1)	1	
Other income	(4)	(4)	(0)		(8)	(8)	1	
EBIT	213	222	(9)		677	677	(0)	
Interest Expense	49	50	1		154	154	(1)	
Income from Ongoing Operations before income taxes	163	172	(8)		523	524	(1)	
Income Tax Expense	61	64	3		195	196	1	
Net Income (loss) from ongoing operations	**102**	**108**	**(5)**		**328**	**328**	**(0)**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	2	(1)	2		(1)	(1)	1	
Net Income (loss)	$ 105	$ 107	$ (3)		$ 327	$ 326	$ 1	
KY Regulated Financing Costs	(14)	(13)	(1)		(37)	(37)	-	
KY Regulated Net Income	$ 90	$ 94	$ (4)		$ 290	$ 289	$ 1	
Earnings Per Share	$ 0.15	$ 0.16	$ (0.00)		$ 0.44	$ 0.46	$ (0.02)	

Electric Gross Margin — April 2013

($ Millions)

	MTD						YTD					
	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance
Base Electric Margin:						$ (8) ◆						$ (13) ◆
Energy Volumes (a)	2,366,126	2,396,212	(30,086)	$ 24.66	$ (2)		10,851,101	10,772,278	78,823	$ 28.44	$ 1	
Energy Prices (a)					(4)						(3)	
Customer Charges (Avg. Customers)	935,049	945,073	(10,024)		-		935,546	943,854	(8,309)		1	
Demand Charges (b)					(2)						(12)	
ECR:						(1) ◆						(3) ◆
Average Rate Base	$ 607	$ 696	$ (89)	10.44%	$ (0.7)		$ 550	$ 620	$ (70)	10.44%	$ (2.2)	
Cost of Capital	10.28%	10.44%	-0.15%	$ 607	(0.1)		10.35%	10.44%	-0.09%	$ 550	(0.2)	
Jurisdictional Factor	89.89%	88.96%	0.94%	$ 607	-		88.39%	87.72%	0.67%	$ 550	0.1	
Other					(0.1)						(0.7)	
DSM:						(0) ◆						1 ●
Program Expense (Revenue Net of Expense)	$ (0.7)	$ (0.2)			$ (0.5)		$ (0.7)	$ (0.9)			$ 0.2	
Lost Sales	1.0	1.0			-		4.6	4.1			0.5	
Incentive	0.1	0.1			-		0.3	0.2			0.1	
Balancing Adjustment	0.3	-			0.3		0.1	-			0.1	
Net Fuel Recovery	$ (0.2)	$ (0.7)				1 ●	$ 1	$ (3)				4 ●
Purchase Power Demand						(1) ◆						0 ●
Transmission						0 ●						1 ●
Other						1 ●						(0) ◆
Retail Margin Variance						(8) ◆						(11) ◆
Off-System Margin Variance						- ●						0 ●
Electric Margin Variance						$ (8) ◆						$ (11) ◆

(a) Non-Fuel Energy Analysis (net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 32	649,281	$ 48.67	$ 33	691,124	$ 48.34	$ (2) ◆	$ (2) ◆	$ 0 ●
Commercial	18	572,837	31.14	19	591,558	31.42	(1) ◆	(1) ◆	(0) ◆
Industrial	4	791,514	5.58	7	762,892	8.71	(2) ◆	0 ●	(3) ◆
Municipals	1	137,955	4.68	1	133,369	4.69	- ●	- ●	- ●
Other	4	214,539	17.91	5	217,269	23.14	(1) ◆	(0) ◆	(1) ◆
Native Load Total	**$ 58**	**2,366,126**	**$ 24.66**	**$ 64**	**2,396,212**	**$ 26.83**	**$ (6) ◆**	**$ (2) ◆**	**$ (4) ◆**

(a) Non-Fuel Energy Analysis (net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 180	3,737,751	$ 48.19	$ 179	3,717,148	$ 48.09	$ 1 ●	$ 1 ●	$ 0 ●
Commercial	80	2,470,023	32.33	81	2,484,538	32.48	(1) ◆	(1) ◆	(0) ◆
Industrial	27	3,124,603	8.52	27	3,076,925	8.79	(0) ◆	0 ●	(1) ◆
Municipals	3	623,253	4.68	3	591,776	4.69	0 ●	0 ●	- ●
Other	19	895,471	21.34	21	901,892	23.63	(2) ◆	(0) ◆	(2) ◆
Native Load Total	**$ 309**	**10,851,101**	**$ 28.44**	**$ 311**	**10,772,278**	**$ 28.83**	**$ (2) ◆**	**$ 1 ●**	**$ (3) ◆**

(b) Demand Analysis (net of base ECR revenue):	MTD			YTD		
$mil	Act	Bud	Variance	Act	Bud	Variance
Commercial	12	13	(1)	47	51	(5)
Industrial	16	17	(1)	61	67	(5)
Municipals	3	4	(1)	15	17	(2)
Other	5	5	1	19	19	0
Native Load Total	**36**	**38**	**(2)**	**141**	**153**	**(12)**

Weather Statistics	MTD			YTD		
	Act	+/- Bud		Act	+/- Bud	
Heating Degree Days - Louisville	270	20	8%	2,668	152	6%
Heating Degree Days - Lexington	296	(2)	-1%	2,811	97	4%
Cooling Degree Days - Louisville	37	5	16%	37	0	0%
Cooling Degree Days - Lexington	29	9	45%	29	6	26%

Gas Gross Margin

April 2013

($ Millions)

	MTD					YTD				
	Actual	Budget	Subtotal	Margin Variance		Actual	Budget	Subtotal	Margin Variance	
Gas Base Service Charge	**$ 8**	**$ 5**		**$ 3**	🟢	**$ 23**	**$ 20**		**$ 3**	🟢
Gas Supply Costs										
Gas Supply Costs	(11)	(8)	$ (2)			(82)	(82)	$ (1)		
GSC Revenue	11	9	1			83	83	(0)		
Net Gas Supply Costs				**(1)**	♦				**(1)**	♦
Retail Gas (a)	**5**	**5**		**1**	🟢	**47**	**45**		**3**	🟢
Wholesale Gas (a)	**-**	**-**		**-**	🟢	**-**	**-**		**-**	🟢
DSM	**0**	**0**		**0**	🟢	**0**	**0**		**0**	🟢
GLT	**0**	**0**		**-**	🟢	**1**	**1**		**0**	🟢
WNA	**(1)**	**-**		**(1)**	♦	**(2)**	**-**		**(2)**	♦
Other Margin	**0**	**0**		**(0)**	♦	**1**	**1**		**(0)**	♦
Gas Margin Variance				**$ 2**	🟢				**$ 2**	🟢

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 3	1,216,273	$ 2.64	$ 3	1,123,113	$ 2.62	$ 0 🟢	$ 0 🟢	$ - 🟢
Commercial	1	563,320	1.73	1	488,561	2.05	- 🟢	0 🟢	(0) ♦
Industrial	0	88,835	1.28	0	67,590	1.81	- 🟢	- 🟢	- 🟢
Public Authority	0	124,927	1.60	0	111,760	1.93	- 🟢	- 🟢	- 🟢
Transportation	1	963,563	0.86	0	779,156	0.43	1 🟢	0 🟢	0 🟢
Ultimate Consumer	$ 5	2,956,918	$ 1.80	$ 5	2,570,179	$ 1.80	$ 1 🟢	$ 1 🟢	$ 0 🟢

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 31	11,626,932	$ 2.64	$ 30	11,687,445	$ 2.57	$ 1 🟢	$ (0) ♦	$ 1 🟢
Commercial	10	4,855,790	2.06	10	4,821,603	2.05	0 🟢	0 🟢	- 🟢
Industrial	1	489,298	1.76	1	415,369	1.86	0 🟢	0 🟢	- 🟢
Public Authority	2	905,970	1.99	2	901,446	1.98	- 🟢	- 🟢	- 🟢
Transportation	4	4,878,653	0.78	2	4,824,864	0.45	2 🟢	- 🟢	2 🟢
Ultimate Consumer	$ 47	22,756,643	$ 2.07	$ 45	22,650,727	$ 1.97	$ 3 🟢	$ 0 🟢	$ 2 🟢

O&M April 2013

($ Millions)

	MTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 26	$ 24	$ (2)	$ -	$ 0	$ (2)	$ (3)	$ 0	$ -	$ 2
Project Engineering	0	0	(0)	-	0	-	(0)	(0)	-	0
Transmission	3	2	(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	3	3	0	-	0	-	0	0	(0)	(0)
Customer Services	7	7	0	-	0	-	0	0	(0)	0
Chief Operations Officer	**45**	**43**	**(2)**	**-**	**0**	**(2)**	**(3)**	**0**	**(0)**	**3**
Information Technology	4	4	0	-	0	-	(0)	0	-	0
General Counsel	2	3	0	-	0	-	1	0	-	(0)
Human Resources	1	1	0	-	0	-	0	0	-	0
Supply Chain	0	0	0	-	(0)	-	0	0	-	0
Chief Administrative Officer	**7**	**8**	**1**	**-**	**0**	**-**	**0**	**0**	**-**	**(0)**
Chief Financial Officer	**1**	**2**	**0**	**-**	**0**	**-**	**(0)**	**0**	**-**	**0**
Corporate	**12**	**12**	**0**	**(0)**	**(0)**	**-**	**1**	**0**	**0**	**(1)**
O&M Total MTD	**$ 65**	**$ 64**	**$ (1)**	**$ (0)**	**$ 0**	**$ (2)**	**$ (2)**	**$ 1**	**$ 0**	**$ 2**

	YTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 79	$ 75	$ (4)	$ -	$ 2	$ (4)	$ (3)	$ (2)	$ -	$ 3
Project Engineering	0	0	0	-	0	-	(0)	(0)	-	0
Transmission	9	9	0	-	(0)	-	0	0	-	(0)
Energy Supply and Analysis	3	4	1	-	0	-	0	0	-	0
Electric Distribution	22	23	1	-	0	-	(0)	0	(0)	1
Gas Distribution	10	10	(0)	-	0	-	(0)	(0)	(0)	(0)
Customer Services	25	29	4	-	1	-	1	0	2	0
Chief Operations Officer	**149**	**151**	**1**	**-**	**3**	**(4)**	**(3)**	**(2)**	**2**	**5**
Information Technology	16	16	(0)	-	0	-	(1)	(0)	-	0
General Counsel	9	10	1	-	0	-	1	0	-	(0)
Human Resources	2	2	0	-	(0)	-	0	0	-	0
Supply Chain	1	1	0	-	0	-	0	0	-	0
Chief Administrative Officer	**29**	**29**	**1**	**-**	**1**	**-**	**(0)**	**(0)**	**-**	**1**
Chief Financial Officer	**5**	**6**	**1**	**-**	**(0)**	**-**	**(0)**	**0**	**-**	**1**
Corporate (a)	**55**	**49**	**(6)**	**(7)**	**(0)**	**-**	**1**	**1**	**0**	**(1)**
O&M Total YTD	**$ 238**	**$ 235**	**$ (3)**	**$ (7)**	**$ 4**	**$ (4)**	**$ (2)**	**$ (2)**	**$ 2**	**$ 5**

(a) Variance due mainly to $7m of jurisdictionalized pension regulatory asset write-off.

	Full Year			Variances						
	Forecast	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 227	$ 227	$ 1	$ -	$ 2	$ (1)	$ (1)	$ (1)	$ -	$ 2
Project Engineering	1	1	0	-	0	-	(0)	(0)	-	0
Transmission	29	29	0	-	(0)	-	1	(1)	-	0
Energy Supply and Analysis	10	11	1	-	1	-	0	0	-	0
Electric Distribution	69	70	1	-	(1)	-	1	0	-	1
Gas Distribution	35	34	(1)	-	(0)	-	0	-	-	(1)
Customer Services	89	91	2	-	1	-	2	0	2	(2)
Chief Operations Officer	**459**	**463**	**4**	**-**	**2**	**(1)**	**2**	**(2)**	**2**	**0**
Information Technology	49	49	(0)	-	0	-	(0)	-	-	(0)
General Counsel	33	34	1	-	0	-	1	-	-	0
Human Resources	7	7	0	-	0	-	0	(0)	-	(0)
Supply Chain	3	3	-	-	-	-	-	-	-	-
Chief Administrative Officer	**92**	**94**	**1**	**-**	**1**	**-**	**1**	**(0)**	**-**	**(0)**
Chief Financial Officer	**19**	**19**	**0**	**-**	**0**	**-**	**(0)**	**-**	**-**	**0**
Corporate	**149**	**146**	**(3)**	**(5)**	**(0)**	**-**	**1**	**0**	**(0)**	**1**
O&M Total Full Year	**$ 719**	**$ 721**	**$ 2**	**$ (5)**	**$ 3**	**$ (1)**	**$ 4**	**$ (2)**	**$ 2**	**$ 1**

Financing Activities April 2013

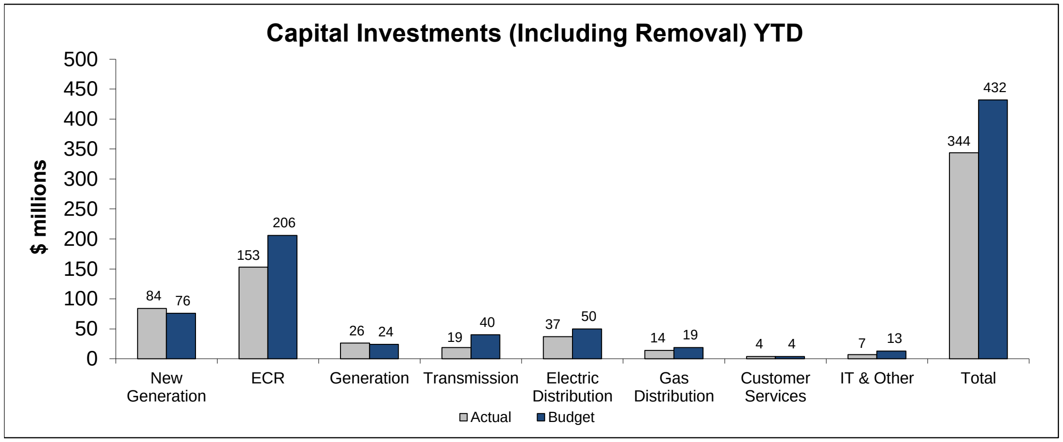
($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB									
Beg Bal	$ 931.9	$ 931.9	$ -	$ 932.0	$ 932.0	$ 0.0	$ 932.0	$ 932.0	$ -
End Bal	931.9	931.9	-	931.9	931.9	-	931.7	931.7	-
Ave Bal	**$ 931.9**	**$ 931.9**	**$ -**	**$ 932.0**	**$ 932.0**	**$ (0.0)**	**$ 931.8**	**$ 931.8**	**$ -**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.2**	**$ 3.5**	**$ 4.6**	**$ 1.1**	**$ 12.7**	**$ 13.6**	**$ 0.9**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.11%**	**1.47%**	**0.36%**	**1.37%**	**1.46%**	**0.09%**
FMB/Sr Nts									
Beg Bal	$ 3,143.2	$ 3,143.2	$ (0.0)	$ 3,142.8	$ 3,142.8	$ 0.0	$ 3,142.8	$ 3,142.8	$ 0.0
End Bal	3,143.3	3,143.3	(0.0)	3,143.3	3,143.3	(0.0)	3,694.4	3,694.4	(0.0)
Ave Bal	**$ 3,143.3**	**$ 3,143.3**	**$ (0.0)**	**$ 3,143.0**	**$ 3,143.1**	**$ 0.1**	**$ 3,235.3**	**$ 3,235.3**	**$ (0.0)**
Interest Exp	**$ 9.6**	**$ 9.6**	**$ (0.0)**	**$ 38.2**	**$ 38.2**	**$ (0.0)**	**$ 120.2**	**$ 120.2**	**$ (0.0)**
Rate	**0.00%**	**0.00%**	**0.00%**	**3.65%**	**3.65%**	**0.00%**	**3.72%**	**3.72%**	**0.00%**
Short-term Debt									
Beg Bal	$ 269.8	$ 224.5	$ (45.3)	$ 149.7	$ 149.7	$ (0.0)	$ 149.7	$ 149.7	$ (0.0)
End Bal	263.3	271.1	7.8	263.3	271.1	7.8	210.5	176.3	(34.2)
Ave Bal	**$ 266.5**	**$ 247.8**	**$ (18.7)**	**$ 206.5**	**$ 258.3**	**$ 51.8**	**$ 372.4**	**$ 359.1**	**$ (13.3)**
Interest Exp	**$ 0.2**	**$ 0.2**	**$ (0.0)**	**$ 753.6**	**$ 655.1**	**$ (98.6)**	**$ 2.9**	**$ 1.2**	**$ (1.7)**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.09%**	**0.76%**	**-0.33%**			
Total End Bal	**$ 4,338.6**	**$ 4,346.3**	**$ 7.8**	**$ 4,338.6**	**$ 4,346.3**	**$ 7.8**	**$ 4,836.6**	**$ 4,802.4**	**$ (34.2)**
Total Average Bal	**$ 4,341.7**	**$ 4,323.0**	**$ (18.7)**	**$ 4,281.5**	**$ 4,333.4**	**$ 51.9**	**$ 4,539.6**	**$ 4,526.3**	**$ (13.3)**
Total Expense Excl I/C	**$ 12.3**	**$ 12.5**	**$ 0.1**	**$ 49.3**	**$ 49.9**	**$ 0.6**	**$ 154.4**	**$ 153.8**	**$ (0.6)**
Rate	**3.65%**	**3.71%**	**0.05%**	**3.46%**	**3.45%**	**0.00%**	**3.40%**	**3.40%**	**0.00%**

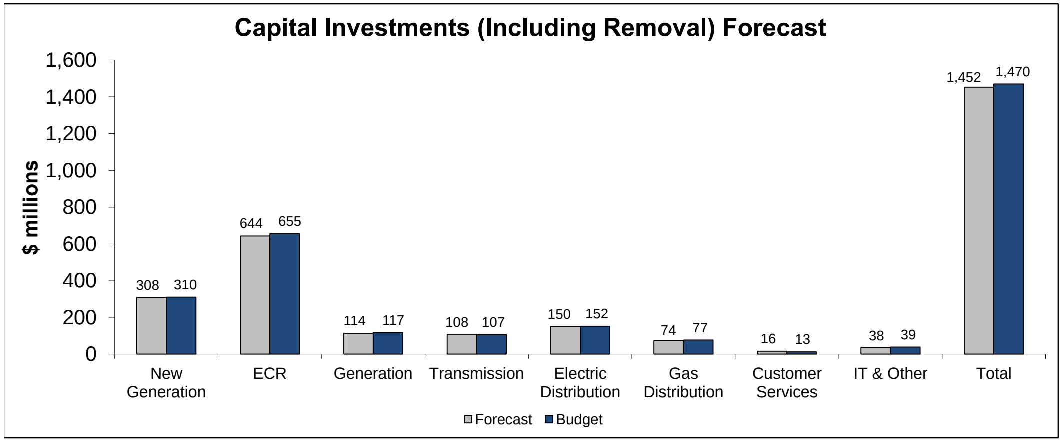
Balance Sheet April 2013

($ Millions)

	YTD	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 59	$ 9	$ 49	Driven by lower capital spend than budgeted.
Accounts Receivable (Trade)	331	300	32	Tariff rate variance in receivable logic and extended due date granted in rate case.
Inventory	241	226	15	Increase in fuel ($9m), gas ($4m) and materials and supplies ($2m).
Deferred Income Taxes	13	13	(1)	
Prepayments and other current assets	53	69	(16)	Primarily due to receivables from insurance claims ($5m), IMEA/IMPA ($4m), interest ($3m), prepaid insurance ($3m) and mutual aid ($2m).
Total Current Assets	697	617	80	
Property, Plant, and Equipment	8,547	8,633	(86)	See capital chart for details.
Intangible Assets	254	254	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets	639	637	2	
Goodwill	997	997	-	
Other Long-term Assets	103	105	(2)	
Total Assets	**$ 11,238**	**$ 11,245**	**$ (7)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 316	$ 248	$ 68	Primarily due to higher fuel volumes and higher capex accrual.
Accounts Payable - Affiliated Company	-	(0)	0	
Customer Deposits	49	48	1	
Derivative Liability	5	5	0	
Accrued Taxes	20	55	(35)	Tax payments made in actuals but not in budget until June.
Other Current Liabilities	151	139	12	Primarily higher accrued salaries than budgeted ($3m) and litigation proceeds not budgeted ($7m).
Total Current Liabilities	542	495	47	
Debt - Affiliated Company	-	-	-	
Debt	4,339	4,346	(8)	
Total Debt	4,339	4,346	(8)	
Deferred Tax Liabilities	588	591	(3)	
Investment Tax Credit	137	137	1	
Accumulated Provision for Pension and Related Benefits	265	267	(2)	
Asset Retirement Obligation	127	127	(0)	
Regulatory Liabilities	992	1,005	(13)	Primarily due to decrease in ECR (-5m), GSC (-3m), spare parts (-2m) and DSM (-2m), partially offset by increase in GLT (2m).
Derivative Liability	52	54	(2)	
Other Liabilities	236	238	(2)	
Total Deferred Credits and Other Liabilities	2,397	2,418	(21)	
Equity	3,960	3,985	(25)	
Total Liabilities and Equity	**$ 11,238**	**$ 11,245**	**$ (7)**	



Capital was $88m lower than budget due mainly to revised schedules for Mill Creek and Ghent environmental air work ($49m) expected to reverse by the end of 2013. Temporary differences on other environmental projects ($4m) and delayed spending on major Transmission and Distribution projects ($39m) are expected to reverse by year end and were partially offset by increased spend on Cane Run 7 ($8m).



Capital is projected to be $18m lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.

Performance Report

May 2013

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Kentucky Regulated Dashboard

May 2013

Operational Metrics	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.57	4.30	1.03	1.52	N/A	1.35
Employee lost-time incidents	0	3	0	3	N/A	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,730	2,683	13,921	14,108	34,925	35,128
Utility EFOR	4.9%	5.1%	8.5%	5.1%	N/A	5.1%
Utility EAF	76.1%	86.4%	76.8%	85.3%	N/A	87.08%
Combined SAIFI	0.09	0.13	0.35	0.43	N/A	1.22
Combined SAIDI (minutes)	8.09	12.68	31.69	39.72	N/A	109.60
GwH Sales						
Residential	745	690	4,483	4,407	10,974	10,912
Commercial	649	658	3,119	3,142	8,067	8,063
Industrial	859	852	3,983	3,928	9,910	9,891
Municipals	142	161	765	753	1,971	1,944
Other	229	246	1,125	1,149	2,897	2,901
Off-System Sales	73	47	178	308	311	465
Total	2,697	2,653	13,653	13,687	34,130	34,175
Weather-Normalized Sales Growth(1)			**W-N**			
Residential			2.56%			
Commercial			-0.57%			
Industrial			2.77%			
Other(2)			-1.74%			
Total			1.23%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE(3)	8.7%	5.8%	9.5%	9.2%	9.6%	9.6%
Electric Margins	$130	$124	$639	$644	$1,625	$1,638
Gas Margins	$9	$9	$80	$77	$157	$156
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$23	$27	$107	$103	$308	$310
ECR	37	53	191	259	644	655
Generation	14	15	40	39	114	117
Transmission	10	9	29	49	108	107
Electric Distribution	12	15	48	65	150	152
Gas Distribution	5	7	19	26	74	77
Customer Services	2	1	6	5	16	13
IT and Other	2	4	9	17	38	39
Total	$105	$131	$449	$563	$1,452	$1,470
O&M ($ millions)(4)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$36	$43	$185	$194	$459	$463
Administrative	$7	8	$36	$37	92	94
Finance and Accounting	$2	2	$7	$8	19	19
Corp Burdens & Other Charges	$12	12	$67	$61	149	146
Total	$56	$65	$295	$300	$719	$721
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,340	3,408	3,340	3,408	3,435	3,435
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	1	3	1	N/A	14
NERC Possible Violations(5)	0	3	3	8	N/A	29

Variance Explanations

- The generation fleet's EAF and EFOR are unfavorable YTD to budget due to temperature and balance issues on Ghent U4 ID fan bearing; turbine bearing failure, air heater pluggage and start-up failure generator lockout on Trimble County U2; hydrogen seal leak and damaged bearing on Mill Creek U4; damaged boiler corner support hangers on Brown U3 and air heater fouling on Ghent U3 & U4.
- Higher margins in May due to $4 million of higher electric energy and demand revenues and $2 million of higher DSM revenue (timing).
- Lower margins YTD due primarily to $10 million of lower electric demand revenues, partially offset by $3 million of higher DSM revenue with increased activity in certain energy efficiency programs and $3 million of higher gas margins.
- Capital was $114 million lower than budget YTD due mainly to revised schedules for environmental air work at Mill Creek for $27 million and Ghent for $21 million. Temporary differences on Ghent and Brown landfill projects of $13 million, other environmental projects of $7 million and delayed spending on major Transmission and Distribution projects of $43 million are expected to reverse by year end.
- Full year capital is projected to be $18 million lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.
- Lower other operation and maintenance in May related to timing of $6 million of lower outage maintenance and supplies and $2 million of labor savings.
- Lower other operation and maintenance YTD primarily related to $6 million of labor savings and other offsetting variances.

Major Developments

- LG&E and KU continue to expand customer commitment with a newly created Online Customer Panel which will include 1,000 customers, whose survey responses will help better understand customer's energy needs, opinions and preferences. Key findings from the surveys will be shared with the participants and employees. Participants will remain on the online panel for one year before another round of invitation letters will invite a new group of customers to join.
- LKE was recently recognized by the American Heart Association for the second year in a row as a Platinum Fit-Friendly Worksite. LKE was recognized for its commitment to health and wellness through initiatives such as WellFairs, the hypertension management program and others.

Significant Future Events

- The Engineering, Procurement and Construction contract is under final evaluation for the Brown 3 fabric filter and is expected to be executed in July.
- In addition to the construction of Cane Run Unit 7, LG&E and KU continue to evaluate responses received from their request for proposals for up to 700 MW of capacity beginning as early as 2015. A final decision is expected early Q3.
- Regarding the Virginia rate case, Virginia State Corporation Commission (VSCC) staff have been on site for a two-week rate case discovery effort. A public hearing will be held on June 24, 2013 in Norton, VA to receive testimony from public witnesses. A second hearing will be held on October 1, 2013 at the VSCC office to receive testimony of public witnesses and the evidence offered by KU, respondents and the Commission's staff.

(1) Percentages represent a trailing twelve months.

(2) "Other" is typically comprised of the public authority customer class and KU's 12 full-requirements wholesale municipal customers.

(3) Excludes goodwill and other purchase accounting adjustments.

(4) Net of cost recovery mechanisms.

(5) The 3 NERC Possible Violation Issues for YTD Actual are expected to be resolved through NERC's Find, Fix and Track ("FFT") process without financial penalty.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget and Forecast (Month) May 2013

($ Millions)

	MTD				MTD			
	Actual	Budget	Variance	Comments	Actual	Q1 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 218	$ 208	$ 9	Average cooling degree days up 35% in May compared to budget.	$ 218	$ 207	$ 10	Favorable weather.
Gas Revenues	16	15	1		16	15	1	
Total Revenues	234	223	10		234	222	11	
Cost of Sales:								
Fuel Electric Costs	74	70	(3)		74	70	(3)	
Gas Supply Expenses	7	6	(1)		7	6	(1)	
Purchased Power	5	6	1		5	6	1	
Other Electric Cost	9	9	(0)		9	8	(1)	
Total Cost of Sales	94	90	(4)		94	90	(4)	
Gross Margin:								
Electric Margin	130	124	6		130	123	7	
Gas Margin	9	9	0		9	9	0	
Total Gross Margin	139	133	6	Due to $4m of higher electric energy and demand revenues and $2m of higher DSM revenue (timing).	139	132	7	Due primarily to higher electric energy and demand and DSM revenues.
Operating Expenses:								
O&M	56	65	9	Related to timing of $6m of lower outage maintenance and supplies and $2m of labor savings.	56	61	5	Favorable labor and burdens, outage timing, uncollectible accounts, outside services and materials and supplies.
Depreciation & Amortization	27	28	1		27	27	(0)	
Taxes, Other than Income	4	4	0		4	4	0	
Total Operating Expenses	87	97	9		87	92	5	
Equity in earnings	-	(0)	0		-	0	(0)	
Other income	(0)	(1)	1		(0)	(1)	1	
EBIT	52	35	16		52	39	13	
Interest Expense	13	13	(0)		13	13	0	
Income from Ongoing Operations before income taxes	39	23	16		39	26	13	
Income Tax Expense	15	8	(6)	Due to higher pre-tax income.	15	10	(5)	Due to higher pre-tax income.
Net Income (loss) from ongoing operations	**24**	**14**	**10**		**24**	**17**	**8**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	(0)	(0)	0		(0)	0	(0)	
Net Income (loss)	$ 24	$ 14	$ 10		$ 24	$ 17	$ 8	
KY Regulated Financing Costs	(8)	(3)	(5)	Higher acquisition financing costs due to early remarketing of the 2010 Equity Units budgeted in June.	(8)	(3)	(5)	Higher acquisition financing costs due to early remarketing of the 2010 Equity Units budgeted in June.
KY Regulated Net Income	$ 16	$ 11	$ 5		$ 16	$ 13	$ 3	
Earnings Per Share	$ 0.04	$ 0.02	$ 0.02		$ 0.04	$ 0.02	$ 0.01	

Income Statement: Actual vs. Budget (YTD) and Forecast vs. Budget (Full Year) May 2013

($ Millions)

	YTD				Full Year			
	Actual	Budget	Variance	Comments	Q1 Forecast	Budget	Variance	Comments
Revenues:								
Electric Revenues	$ 1,080	$ 1,079	$ 1		$ 2,732	$ 2,753	$ (21)	Lower retail and wholesale demand volumes and lower ECR returns.
Gas Revenues	169	167	2		311	313	(2)	
Total Revenues	1,249	1,246	3		3,043	3,065	(23)	
Cost of Sales:								
Fuel Electric Costs	375	367	(7)	Higher retail volumes partially offset by lower wholesale volumes and start-up fuel costs.	928	928	(0)	
Gas Supply Expenses	89	90	1		154	157	3	
Purchased Power	25	25	0		68	67	(1)	
Other Electric Cost	41	43	1		111	119	8	Lower electric volumes and ECR costs.
Total Cost of Sales	530	525	(5)		1,261	1,271	10	
Gross Margin:								
Electric Margin	639	644	(5)	Due primarily to $10m of lower electric demand revenues, partially offset by $3m of higher DSM revenue with increased activity in certain energy efficiency programs.	1,625	1,638	(13)	Q1 margin shortfall of $3m, lower ECR of $3m due to delayed capital spend, and lower demand projections of $7m.
Gas Margin	80	77	3		157	156	1	
Total Gross Margin	719	721	(2)		1,782	1,794	(12)	
Operating Expenses:								
O&M	295	300	5	Primarily related to $6m of labor savings and other offsetting variances.	719	721	2	
Depreciation & Amortization	136	140	3		329	338	8	Revised estimates based on delayed capital spend in 2012 and revised in-service dates for capital projects in 2013.
Taxes, Other than Income	20	20	0		48	48	(0)	
Total Operating Expenses	451	460	9		1,097	1,107	10	
Equity in earnings	-	(0)	0		0	(1)	1	
Other income	(4)	(5)	0		(8)	(8)	1	
EBIT	264	257	8		677	677	(0)	
Interest Expense	62	62	0		154	154	(1)	
Income from Ongoing Operations before income taxes	202	194	8		523	524	(1)	
Income Tax Expense	76	72	(4)		195	196	1	
Net Income (loss) from ongoing operations	**127**	**122**	**5**		**328**	**328**	**(0)**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	2	(1)	3		(1)	(1)	1	
Net Income (loss)	$ 129	$ 121	$ 8		$ 327	$ 326	$ 1	
KY Regulated Financing Costs	(23)	(17)	(6)	Higher acquisition financing costs due to early remarketing of the 2010 Equity Units budgeted in June.	(40)	(37)	(2)	
KY Regulated Net Income	$ 106	$ 104	$ 2		$ 288	$ 289	$ (1)	
Earnings Per Share	$ 0.19	$ 0.18	$ 0.01		$ 0.46	$ 0.46	$ 0.00	

Electric Gross Margin May 2013

($ Millions)

	MTD Actual	MTD Budget	MTD Unit Variance	MTD Value @	MTD Dollar Variance	MTD Margin Variance	YTD Actual	YTD Budget	YTD Unit Variance	YTD Value @	YTD Dollar Variance	YTD Margin Variance
Base Electric Margin:						$ 3 🟢						$ (10) ♦
Energy Volumes (a)	2,623,529	2,606,757	16,772	$ 26.51	$ 2		13,474,630	13,379,035	95,595	$ 28.07	$ 3	
Energy Prices (a)					(1)						(4)	
Customer Charges (Avg. Customers)	935,109	945,126	(10,017)		-		935,458	944,109	(8,650)		1	
Demand Charges (b)					2						(10)	
ECR:						(1) ♦						(4) ♦
Average Rate Base	$ 650	$ 747	$ (98)	10.44%	$ (0.7)		$ 570	$ 645	$ (76)	10.44%	$ (2.9)	
Cost of Capital	10.29%	10.44%	-0.15%	$ 650	(0.1)		10.33%	10.44%	-0.11%	$ 570	(0.2)	
Jurisdictional Factor	87.36%	88.62%	-1.26%	$ 650	(0.1)		88.15%	87.93%	0.23%	$ 570	0.1	
Other					(0.4)						(1.1)	
DSM:						2 🟢						3 🟢
Program Expense (Revenue Net of Expense)	$ 0.7	$ (0.2)			$ 0.9		$ -	$ (1.1)			$ 1.1	
Lost Sales	2.5	1.0			1.5		7.1	5.1			2.0	
Incentive	0.2	0.1			0.1		0.5	0.3			0.2	
Balancing Adjustment	(0.5)	-			(0.5)		(0.4)	-			(0.4)	
Net Fuel Recovery	$ 0.4	$ (0.7)				1 🟢	$ 2	$ (4)				5 🟢
Purchase Power Demand						(0) ♦						(0) ♦
Transmission						0 🟢						1 🟢
Other						- 🟢						(0) ♦
Retail Margin Variance						5 🟢						(6) ♦
Off-System Margin Variance						1 🟢						1 🟢
Electric Margin Variance						$ 6 🟢						$ (5) ♦

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD Actual Revenue $mil	MTD Actual Volume (MWH)	MTD Actual Price ($/MWH)	MTD Budget Revenue $mil	MTD Budget Volume (MWH)	MTD Budget Price ($/MWH)	MTD Variance Revenue $mil	MTD Variance Volume $mil	MTD Variance Price $mil
Residential	$ 37	745,090	$ 49.17	$ 34	690,258	$ 48.92	$ 3 🟢	$ 3 🟢	$ 0 🟢
Commercial	20	648,779	30.11	21	657,825	31.38	(1) ♦	(0) ♦	(1) ♦
Industrial	8	858,532	8.80	8	851,541	8.77	0 🟢	0 🟢	- 🟢
Municipals	1	141,684	4.69	1	160,800	4.69	(0) ♦	(0) ♦	- 🟢
Other	5	229,444	22.46	6	246,332	23.36	(1) ♦	(0) ♦	(0) ♦
Native Load Total	**$ 70**	**2,623,529**	**$ 26.51**	**$ 69**	**2,606,757**	**$ 26.23**	**$ 1** 🟢	**$ 2** 🟢	**$ (1)** ♦

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD Actual Revenue $mil	YTD Actual Volume (MWH)	YTD Actual Price ($/MWH)	YTD Budget Revenue $mil	YTD Budget Volume (MWH)	YTD Budget Price ($/MWH)	YTD Variance Revenue $mil	YTD Variance Volume $mil	YTD Variance Price $mil
Residential	$ 217	4,482,841	$ 48.36	$ 213	4,407,406	$ 48.22	$ 4 🟢	$ 4 🟢	$ 1 🟢
Commercial	99	3,118,802	31.87	101	3,142,363	32.25	(2) ♦	(1) ♦	(1) ♦
Industrial	34	3,983,135	8.58	35	3,928,466	8.79	(0) ♦	1 🟢	(1) ♦
Municipals	4	764,937	4.68	4	752,576	4.69	0 🟢	0 🟢	- 🟢
Other	24	1,124,916	21.57	27	1,148,224	23.57	(3) ♦	(1) ♦	(2) ♦
Native Load Total	**$ 378**	**13,474,630**	**$ 28.07**	**$ 379**	**13,379,035**	**$ 28.32**	**$ (1)** ♦	**$ 3** 🟢	**$ (4)** ♦

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD Variance
Commercial	15	14	1	62	65	(4)
Industrial	17	17	0	79	84	(5)
Municipals	4	4	(0)	18	21	(3)
Other	6	5	1	25	24	1
Native Load Total	**42**	**40**	**2**	**184**	**194**	**(10)**

Weather Statistics	MTD Act	MTD +/- Bud		YTD Act	YTD +/- Bud	
Heating Degree Days - Louisville	66	(16)	-20%	2,734	136	5%
Heating Degree Days - Lexington	81	(32)	-28%	2,892	65	2%
Cooling Degree Days - Louisville	149	33	28%	186	33	22%
Cooling Degree Days - Lexington	123	37	43%	152	43	39%

Gas Gross Margin May 2013

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**$ -** 🟢	**$ 28**	**$ 25**		**$ 3** 🟢
Gas Supply Costs								
Gas Supply Costs	(6)	(6)	$ (1)		(89)	(87)	$ (2)	
GSC Revenue	7	6	0		89	89	1	
Net Gas Supply Costs				**(1)** ♦				**(1)** ♦
Retail Gas (a)	**3**	**3**		**0** 🟢	**50**	**48**		**3** 🟢
Wholesale Gas (a)	**-**	**-**		**-** 🟢	**-**	**-**		**-** 🟢
DSM	**1**	**(0)**		**1** 🟢	**1**	**(1)**		**2** 🟢
GLT	**0**	**0**		**(0)** ♦	**1**	**1**		**0** 🟢
WNA	**-**	**-**		**-** 🟢	**(2)**	**-**		**(2)** ♦
Other Margin	**0**	**0**		**(0)** ♦	**1**	**1**		**(1)** ♦
Gas Margin Variance				**$ 0** 🟢				**$ 3** 🟢

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 2	648,568	$ 2.64	$ 2	638,365	$ 2.66	$ - 🟢	$ - 🟢	$ - 🟢
Commercial	1	272,839	1.82	1	370,812	2.06	(0) ♦	(0) ♦	(0) ♦
Industrial	0	71,038	1.45	0	58,142	1.85	- 🟢	- 🟢	- 🟢
Public Authority	0	51,934	1.69	0	64,656	1.91	- 🟢	- 🟢	- 🟢
Transportation	1	852,708	0.89	0	740,349	0.42	1 🟢	- 🟢	0 🟢
Ultimate Consumer	$ 3	1,897,087	$ 1.66	$ 3	1,872,324	$ 1.61	$ 0 🟢	$ (0) ♦	$ 0 🟢

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 32	12,275,500	$ 2.64	$ 32	12,325,810	$ 2.58	$ 1 🟢	$ (0) ♦	$ 1 🟢
Commercial	11	5,128,629	2.04	11	5,192,415	2.05	(0) ♦	(0) ♦	- 🟢
Industrial	1	560,336	1.72	1	473,511	1.86	0 🟢	0 🟢	(0) ♦
Public Authority	2	957,904	1.98	2	966,102	1.98	- 🟢	- 🟢	- 🟢
Transportation	5	5,731,361	0.79	3	5,565,213	0.45	2 🟢	0 🟢	2 🟢
Ultimate Consumer	$ 50	24,653,730	$ 2.04	$ 48	24,523,050	$ 1.94	$ 3 🟢	$ - 🟢	$ 3 🟢

O&M May 2013

($ Millions)

	MTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 17	$ 23	$ 6	$ -	$ 1	$ 4	$ 3	$ 2	$ -	$ (4)
Project Engineering	0	0	0	-	$ 0	-	(0)	(0)	-	0
Transmission	3	3	(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	3	3	1	-	$ 0	-	1	0	0	(0)
Customer Services	7	7	1	-	$ 0	-	(0)	(0)	1	0
Chief Operations Officer	**36**	**43**	**8**	**-**	**1**	**4**	**4**	**2**	**1**	**(5)**
Information Technology	4	4	0	-	0	-	(0)	0	-	0
General Counsel	2	3	0	-	0	-	0	0	-	(0)
Human Resources	1	1	0	-	0	-	0	0	-	(0)
Supply Chain	0	0	0	-	0	-	0	0	-	0
Chief Administrative Officer	**7**	**8**	**1**	**-**	**0**	**-**	**0**	**0**	**-**	**0**
Chief Financial Officer	**2**	**2**	**0**	**-**	**0**	**-**	**(0)**	**0**	**-**	**(0)**
Corporate	**12**	**12**	**0**	**0**	**(0)**	**-**	**0**	**0**	**0**	**(0)**
O&M Total MTD	**$ 56**	**$ 65**	**$ 9**	**$ 0**	**$ 2**	**$ 4**	**$ 4**	**$ 2**	**$ 1**	**$ (5)**

	YTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 97	$ 99	$ 2	$ -	$ 3	$ 2	$ (0)	$ (0)	$ -	$ (3)
Project Engineering	0	0	0	-	0	-	(0)	(0)	-	0
Transmission	12	12	0	-	(0)	-	1	0	-	(0)
Energy Supply and Analysis	4	5	1	-	0	-	0	0	-	0
Electric Distribution	28	29	1	-	0	-	(1)	0	(0)	1
Gas Distribution	13	13	0	-	0	-	1	(0)	(0)	(0)
Customer Services	32	37	5	-	1	-	1	(0)	3	0
Chief Operations Officer	**185**	**194**	**9**	**-**	**5**	**2**	**1**	**(0)**	**3**	**(2)**
Information Technology	20	20	(0)	-	1	-	(1)	(0)	-	1
General Counsel	12	13	1	-	0	-	1	0	-	(0)
Human Resources	2	3	0	-	(0)	-	0	0	-	0
Supply Chain	1	2	0	-	0	-	0	0	-	0
Chief Administrative Officer	**36**	**37**	**2**	**-**	**1**	**-**	**(0)**	**(0)**	**-**	**1**
Chief Financial Officer	**7**	**8**	**1**	**-**	**0**	**-**	**(0)**	**0**	**-**	**1**
Corporate (a)	**67**	**61**	**(6)**	**(6)**	**(1)**	**-**	**2**	**1**	**0**	**(2)**
O&M Total YTD	**$ 295**	**$ 300**	**$ 5**	**$ (6)**	**$ 5**	**$ 2**	**$ 3**	**$ 1**	**$ 3**	**$ (2)**

(a) Variance due mainly to $7m of jurisdictionalized pension regulatory asset write-off.

	Full Year			Variances						
	Forecast	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 227	$ 227	$ 1	$ -	$ 2	$ (1)	$ (1)	$ (1)	$ -	$ 2
Project Engineering	1	1	0	-	0	-	(0)	(0)	-	0
Transmission	29	29	0	-	(0)	-	1	(1)	-	0
Energy Supply and Analysis	10	11	1	-	1	-	0	0	-	0
Electric Distribution	69	70	1	-	(1)	-	1	0	-	1
Gas Distribution	35	34	(1)	-	(0)	-	0	-	-	(1)
Customer Services	89	91	2	-	1	-	2	0	2	(2)
Chief Operations Officer	**459**	**463**	**4**	**-**	**2**	**(1)**	**2**	**(2)**	**2**	**0**
Information Technology	49	49	(0)	-	0	-	(0)	-	-	(0)
General Counsel	33	34	1	-	0	-	1	-	-	0
Human Resources	7	7	0	-	0	-	0	(0)	-	(0)
Supply Chain	3	3	-	-	-	-	-	-	-	-
Chief Administrative Officer	**92**	**94**	**1**	**-**	**1**	**-**	**1**	**(0)**	**-**	**(0)**
Chief Financial Officer	**19**	**19**	**0**	**-**	**0**	**-**	**(0)**	**-**	**-**	**0**
Corporate	**149**	**146**	**(3)**	**(5)**	**(0)**	**-**	**1**	**0**	**(0)**	**1**
O&M Total Full Year	**$ 719**	**$ 721**	**$ 2**	**$ (5)**	**$ 3**	**$ (1)**	**$ 4**	**$ (2)**	**$ 2**	**$ 1**

Financing Activities May 2013

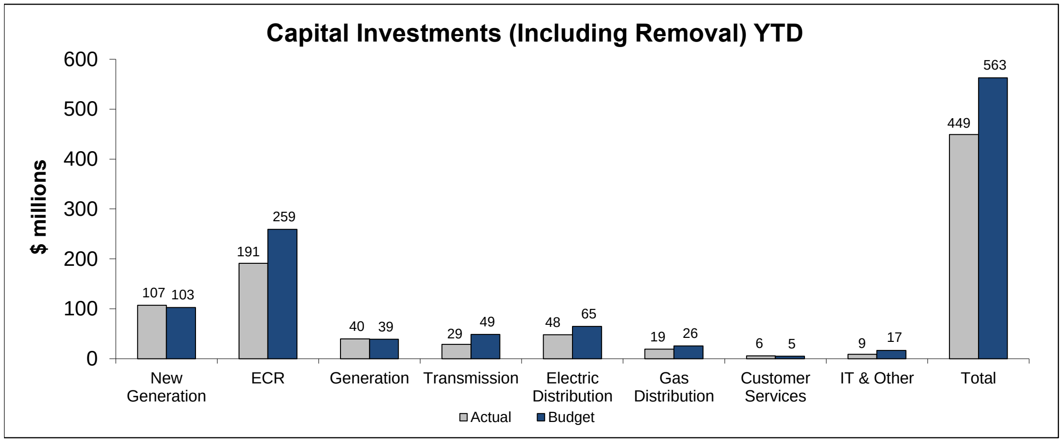
($ Millions)

Balance Sheet	MTD			YTD			Full Year		
	Actual	Budget	Variance	Actual	Budget	Variance	Forecast	Budget	Variance
PCB									
Beg Bal	$ 931.9	$ 931.9	$ -	$ 932.0	$ 932.0	$ 0.0	$ 932.0	$ 932.0	$ -
End Bal	931.9	931.9	-	931.9	931.9	-	931.7	931.7	-
Ave Bal	$ 931.9	$ 931.9	$ -	$ 932.0	$ 931.9	$ (0.0)	$ 931.8	$ 931.8	$ -
Interest Exp	$ 0.9	$ 1.1	$ 0.2	$ 4.4	$ 5.7	$ 1.4	$ 12.7	$ 13.6	$ 0.9
Rate	0.00%	0.00%	0.00%	1.11%	1.46%	0.35%	1.37%	1.46%	0.09%
FMB/Sr Nts									
Beg Bal	$ 3,143.3	$ 3,143.3	$ (0.0)	$ 3,142.8	$ 3,142.8	$ 0.0	$ 3,142.8	$ 3,142.8	$ 0.0
End Bal	3,143.5	3,143.5	(0.0)	3,143.5	3,143.5	(0.0)	3,694.4	3,694.4	(0.0)
Ave Bal	$ 3,143.4	$ 3,143.4	$ (0.0)	$ 3,143.1	$ 3,143.2	$ 0.1	$ 3,235.3	$ 3,235.3	$ (0.0)
Interest Exp	$ 9.6	$ 9.6	$ (0.0)	$ 47.8	$ 47.8	$ (0.0)	$ 120.2	$ 120.2	$ (0.0)
Rate	0.00%	0.00%	0.00%	3.62%	3.62%	0.00%	3.72%	3.72%	0.00%
Short-term Debt									
Beg Bal	$ 263.3	$ 271.1	$ 7.8	$ 149.7	$ 149.7	$ (0.0)	$ 149.7	$ 149.7	$ (0.0)
End Bal	320.7	411.7	91.0	320.7	411.7	91.0	210.5	176.3	(34.2)
Ave Bal	$ 292.0	$ 341.4	$ 49.4	$ 235.2	$ 289.0	$ 53.8	$ 372.4	$ 359.1	$ (13.3)
Interest Exp	$ 0.2	$ 0.2	$ 0.0	$ 952.7	$ 859.0	$ (93.7)	$ 2.9	$ 1.2	$ (1.7)
Rate	0.00%	0.00%	0.00%	0.97%	0.71%	-0.26%			
Total End Bal	$ 4,396.0	$ 4,487.0	$ 91.0	$ 4,396.0	$ 4,487.0	$ 91.0	$ 4,836.6	$ 4,802.4	$ (34.2)
Total Average Bal	$ 4,367.3	$ 4,416.7	$ 49.4	$ 4,310.2	$ 4,364.1	$ 53.9	$ 4,539.6	$ 4,526.3	$ (13.3)
Total Expense Excl I/C	$ 12.6	$ 12.5	$ (0.1)	$ 61.9	$ 62.4	$ 0.5	$ 154.4	$ 153.8	$ (0.6)
Rate	3.71%	3.64%	-0.07%	3.42%	3.41%	-0.02%	3.40%	3.40%	0.00%

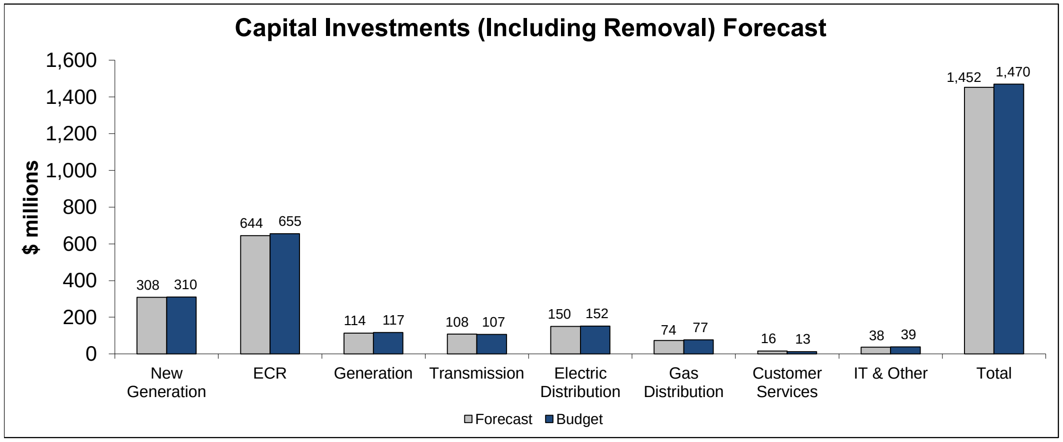
Balance Sheet May 2013

($ Millions)

	YTD	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 20	$ 9	$ 11	
Accounts Receivable (Trade)	330	306	24	Tariff rate variance in receivable logic and extended due date granted in rate case.
Inventory	238	225	12	Primarily increase in fuel ($6m), gas ($4m) and materials and supplies ($3m).
Deferred Income Taxes	13	13	(1)	
Prepayments and other current assets	162	67	95	Primarily due to capital contribution from PPL not included in other receivable budget ($75m); also receivables from insurance claims ($5m), IMEA/IMPA ($3m), interest ($3m), prepaid insurance ($4m) and mutual aid ($2m).
Total Current Assets	763	621	142	
Property, Plant, and Equipment	8,623	8,736	(113)	See capital chart for details.
Intangible Assets	249	250	(1)	
Other Property and Investments	1	1	0	
Regulatory Assets	629	634	(5)	
Goodwill	997	997	-	
Other Long-term Assets	100	105	(5)	
Total Assets	**$ 11,362**	**$ 11,343**	**$ 19**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 275	$ 220	$ 54	Primarily due to higher fuel volumes.
Accounts Payable - Affiliated Company	65	(0)	65	Dividend declared.
Customer Deposits	49	48	1	
Derivative Liability	4	5	(1)	
Accrued Taxes	39	60	(22)	Tax payments made in actuals but not in budget until June.
Other Current Liabilities	114	100	14	Due primarily to wires made but not yet cleared, including payroll funding ($3m), payment to Opower software license ($2m) and payment to KBR for Ghent environmental projects ($10m).
Total Current Liabilities	546	434	112	
Debt - Affiliated Company	-	-	-	
Debt	4,396	4,487	(91)	Less short-term debt issued than budgeted (-$151m) due to lower capital spend, offset by notes payable to PPL ($60m). See Financing Activities page for more details.
Total Debt	4,396	4,487	(91)	
Deferred Tax Liabilities	588	598	(10)	Timing of recording of deferred taxes in actuals vs. budget.
Investment Tax Credit	137	136	1	
Accumulated Provision for Pension and Related Benefits	265	268	(3)	
Asset Retirement Obligation	126	128	(2)	
Regulatory Liabilities	1,028	1,000	28	Due primarily to increase in long-term interest rate swaps ($37m).
Derivative Liability	44	54	(9)	
Other Liabilities	240	239	2	
Total Deferred Credits and Other Liabilities	2,429	2,423	6	
Equity	3,991	3,999	(9)	
Total Liabilities and Equity	**$ 11,362**	**$ 11,343**	**$ 19**	



Capital was $114m lower than budget due mainly to revised schedules for Mill Creek ($27m) and Ghent ($21) environmental air work. Temporary differences on Ghent and Brown landfill projects ($13m), other environmental projects ($7m) and delayed spending on major Transmission and Distribution projects ($43m) are expected to reverse by year end.



Capital is projected to be $18m lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.

Performance Report

June 2013

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Kentucky Regulated Dashboard

June 2013

Operational Metrics	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	2.87	1.85	1.31	1.59	N/A	1.35
Employee lost-time incidents	0	1	0	4	N/A	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,888	3,055	16,809	17,163	34,774	35,128
Utility EFOR	6.3%	5.1%	8.1%	5.1%	N/A	5.1%
Utility EAF	89.1%	92.3%	78.8%	86.4%	N/A	87.08%
Combined SAIFI	0.14	0.17	0.49	0.60	N/A	1.22
Combined SAIDI (minutes)	15.22	14.98	46.91	54.70	N/A	109.60
GwH Sales						
Residential	880	898	5,363	5,305	10,904	10,912
Commercial	646	741	3,765	3,883	7,858	8,063
Industrial	853	900	4,836	4,828	9,949	9,891
Municipals	164	181	929	933	1,904	1,944
Other	237	265	1,362	1,414	2,791	2,901
Off-System Sales	54	9	231	317	380	465
Total	2,833	2,994	16,486	16,681	33,785	34,175
Weather-Normalized Sales Growth(1)			**W-N**			
Residential			1.51%			
Commercial			-1.83%			
Industrial			2.71%			
Other(2)			-2.06%			
Total			0.52%			

Variance Explanations

- The generation fleet's EAF and EFOR are unfavorable YTD to budget due to temperature and balance issues on Ghent U4 ID fan bearing; turbine bearing failure, air heater pluggage and start-up failure generator lockout on Trimble County U2; hydrogen seal leak and damaged bearing on Mill Creek U4; damaged boiler corner support hangers on Brown U3; air heater fouling on Ghent U3 & U4 and winding shorts on generator rotor on Cane Run U4.
- Lower margins in June due primarily to $8 million of lower electric energy and demand charge volumes.
- Lower margins YTD due primarily to $14 million of lower retail electric demand charge revenues, partially offset by net favorable margins on other retail rate mechanisms.
- Capital was $131 million lower than budget YTD due mainly to slower than expected mobilization for Mill Creek of $32 million and Ghent environmental air work of $24 million. Differences on Ghent and Brown landfill projects of $15 million and other environmental projects of $9 million are expected to reverse by year end. Transmission underspend of $21 million was due mainly to delayed spending on Cane Run U7, New Albany transmission work and line rating projects; Distribution variances of $29 million were driven by timing of circuit hardening, major substation projects, main replacement and gas riser projects.
- Full year capital is projected to be $19 million lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.
- Lower other operation and maintenance in June related primarily to $2 million of lower outage costs, $2 million of labor savings and $2 million of lower outside services.
- Lower other operation and maintenance YTD related to $3 million of lower outside services, $3 million of lower uncollectible accounts and $6 million of labor savings.

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE(3)	10.9%	10.5%	9.8%	9.4%	9.6%	9.6%
Electric Margins	$137	$143	$776	$787	$1,609	$1,638
Gas Margins	$7	$8	$87	$86	$157	$156
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$29	$27	$136	$130	$310	$310
ECR	42	55	232	313	637	655
Generation	5	5	45	45	115	117
Transmission	8	9	37	58	107	107
Electric Distribution	11	14	57	75	144	144
Gas Distribution	4	8	23	34	77	77
Customer Services	1	1	7	5	12	9
IT and Other	6	5	18	26	49	51
Total	$106	$124	$555	$686	$1,451	$1,470
O&M ($ millions)(4)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$33	$36	$218	$231	$452	$461
Administrative	$7	8	$43	$45	91	95
Finance and Accounting	$1	2	$9	$9	18	19
Corp Burdens & Other Charges	$10	12	$76	$73	142	146
Total	$52	$58	$346	$358	$704	$721
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,336	3,411	3,336	3,411	3,435	3,435
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	1	3	2	N/A	14
NERC Possible Violations(5)	4	0	7	8	N/A	29

Major Developments

- LG&E and KU were recognized for several safety, communication and customer service awards in the month of June:
  - KU received the prestigious Kentucky Governor's Health and Safety Award for outstanding safety performance. Brown employees won the award for working 4,144,448 hours without a lost-time incident. Ghent employees won the award for working 1,272,552 hours without a lost-time incident.
  - At the Utility Communicators International Gala, LG&E and KU were the recipients of 11 Better Communication Competition Awards - representing the most by any utility. The awards winners were selected from more than 350 entries submitted by 35 utilities across the globe.
  - LG&E and KU's Residential Service Center ("RSC") placed in the Top 10 in the 2013 BenchmarkPortal Top 100 Call Center Contest – Medium Sized Contact Centers (100 - 249 employees). The RSC was also selected as one of four finalists in the International Quality & Productivity Center's Best in Class Call Center (under 200 staff) category for 2013. LG&E and KU received the honorable mention award behind the first and second place finishers.

Significant Future Events

- The Engineering, Procurement and Construction contract is under final evaluation for the Brown 3 fabric filter and is expected to be resolved in Q3.
- In addition to the construction of Cane Run Unit 7, LG&E and KU continue to evaluate responses received from their request for proposals for up to 700 MW of capacity beginning as early as 2015. A final decision is expected in the next few months.

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(1) Percentages represent a trailing twelve months.

(2) "Other" is typically comprised of the public authority customer class and KU's 12 full-requirements wholesale municipal customers.

(3) Excludes goodwill and other purchase accounting adjustments.

(4) Net of cost recovery mechanisms.

(5) The seven NERC Possible Violation Issues for YTD Actual are expected to be resolved through NERC's Find, Fix and Track ("FFT") process without financial penalty.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget and Forecast (Month) June 2013

($ Millions)

	MTD				MTD			
	Actual	**Budget**	**Variance**	**Comments**	**Actual**	**Q1 Forecast**	**Variance**	**Comments**
Revenues:								
Electric Revenues	$ 224	$ 242	$ (17)	Lower energy and demand charge volumes.	$ 224	$ 239	$ (15)	Lower energy volumes and lower demand charge volumes driven by the commercial sector.
Gas Revenues	11	12	(1)		11	12	(1)	
Total Revenues	236	253	(18)		236	251	(15)	
Cost of Sales:								
Fuel Electric Costs	75	82	7	Decreased electric volumes. Offset by unfavorable electric revenues above.	75	82	7	Decreased electric volumes. Offset by unfavorable electric revenues above.
Gas Supply Expenses	4	4	(0)		4	4	(0)	
Purchased Power	5	6	2		5	7	2	
Other Electric Cost	8	10	2		8	9	2	
Total Cost of Sales	91	102	11		91	101	10	
Gross Margin:								
Electric Margin	137	143	(6)	Due primarily to $8m of lower electric energy and demand charge volumes.	137	141	(4)	Due primarily to lower electric energy and demand charge volumes.
Gas Margin	7	8	(1)		7	8	(1)	
Total Gross Margin	144	151	(7)		144	150	(5)	
Operating Expenses:								
O&M	52	58	6	Related primarily to $2m of lower outage costs, $2m of labor savings and $2m of lower outside services.	52	57	6	Favorable outage timing, labor and burdens and outside services.
Depreciation & Amortization	27	28	1		27	27	(0)	
Taxes, Other than Income	4	4	0		4	4	0	
Total Operating Expenses	83	90	7		83	89	6	
Equity in earnings	-	(0)	0		-	0	(0)	
Other income	(0)	(1)	0		(0)	(1)	0	
EBIT	61	61	0		61	61	0	
Interest Expense	12	13	0		12	13	0	
Income from Ongoing Operations before income taxes	49	48	1		49	48	1	
Income Tax Expense	18	18	0		18	18	0	
Net Income (loss) from ongoing operations	**31**	**30**	**1**		**31**	**30**	**1**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	0	(0)	0		0	0	(0)	
Net Income (loss)	$ 31	$ 30	$ 1		$ 31	$ 30	$ 1	
KY Regulated Financing Costs	(3)	(6)	3	Lower related to the remarketing of the 2010 Equity Units in May that was budgeted for June (timing).	(3)	(6)	3	Lower related to the remarketing of the 2010 Equity Units in May that was budgeted for June (timing).
KY Regulated Net Income	$ 28	$ 24	$ 4		$ 28	$ 24	$ 4	
Earnings Per Share	$ 0.04	$ 0.04	$ 0.00		$ 0.04	$ 0.04	$ 0.00	

Income Statement: Actual vs. Budget (YTD) June 2013

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,304	$ 1,321	$ (16)	Due primarily to $14m of lower retail electric demand charge revenues.
Gas Revenues	181	179	2	
Total Revenues	1,485	1,500	(15)	
Cost of Sales:				
Fuel Electric Costs	450	449	(0)	
Gas Supply Expenses	94	93	(0)	
Purchased Power	30	32	2	
Other Electric Cost	49	53	4	Lower electric volumes and ECR costs.
Total Cost of Sales	622	627	5	
Gross Margin:				
Electric Margin	776	787	(11)	Due primarily to $14m of lower retail electric demand charge revenues, partially offset by net favorable margins on other retail rate mechanisms.
Gas Margin	87	86	1	
Total Gross Margin	863	873	(10)	
Operating Expenses:				
O&M	346	358	12	Related to $3m of lower outside services, $3m of lower uncollectible accounts and $6m of labor savings.
Depreciation & Amortization	163	168	4	
Taxes, Other than Income	24	24	0	
Total Operating Expenses	533	550	17	
Equity in earnings	-	(0)	0	
Other income	(5)	(5)	1	
EBIT	325	317	8	
Interest Expense	74	75	1	
Income from Ongoing Operations before income taxes	251	242	9	
Income Tax Expense	94	90	(3)	
Net Income (loss) from ongoing operations	**157**	**152**	**5**	
Non Operating Income	1	-	1	
Discontinued Operations	2	(1)	3	
Net Income (loss)	$ 160	$ 151	$ 9	
KY Regulated Financing Costs	(25)	(22)	(3)	Higher due to revised rates and durations of remarketing of the 2010 Equity Units.
KY Regulated Net Income	$ 134	$ 129	$ 6	
Earnings Per Share	$ 0.23	$ 0.22	$ 0.01	

Income Statement: Forecast vs. Budget and Prior Forecast June 2013

($ Millions)

	Full Year				Full Year			
	Q2 Forecast	Budget	Variance	Comments	Q2 Forecast	Q1 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 2,706	$ 2,753	$ (47)	Lower retail and wholesale demand volumes, lower energy volumes and lower ECR returns.	$ 2,706	$ 2,732	$ (26)	Due primarily to $12 electric revenue shortfall in Q2, $5m lower demand projections and $10m lower energy projections.
Gas Revenues	315	313	3		315	311	5	Due to increased gas revenues in Q2.
Total Revenues	3,021	3,065	(44)		3,021	3,043	(22)	
Cost of Sales:								
Fuel Electric Costs	928	928	(0)		928	928	(0)	
Gas Supply Expenses	158	157	(1)		158	154	(4)	
Purchased Power	66	67	1		66	68	2	
Other Electric Cost	103	119	17	Lower electric volumes and ECR costs.	103	111	8	Lower electric volumes and ECR costs.
Total Cost of Sales	1,255	1,271	16		1,255	1,261	6	
Gross Margin:								
Electric Margin	1,609	1,638	(29)	Primarily Q2 margin shortfall of $10m, lower ECR of $3m due to delayed capital spend, lower demand projections of $12m and lower energy projections of $10m, offset by $7m favorable other cost of sales.	1,609	1,625	(16)	Due to $7m lower Q2 margins, $5m lower demand projections and $10m lower energy projections, offset by $6m favorable cost of sales.
Gas Margin	157	156	1		157	157	0	
Total Gross Margin	1,766	1,794	(28)		1,766	1,782	(15)	
Operating Expenses:								
O&M	704	721	17	Favorable labor and burdens ($6m), uncollectible accounts ($3m), and outside services ($7m).	704	719	15	Related primarily to favorability in Q2 including $4m of lower outage costs, $2m of labor savings, $2m of lower uncollectible accounts and $2m of lower outside services costs.
Depreciation & Amortization	329	338	9	Revised estimates based on delayed capital spend in 2012 and revised in-service dates for capital projects in 2013.	329	329	0	
Taxes, Other than Income	48	48	(0)		48	48	0	
Total Operating Expenses	1,082	1,107	26		1,082	1,097	15	
Equity in earnings	0	(1)	1		0	0	(0)	
Other income	(7)	(8)	1		(7)	(8)	0	
EBIT	677	677	(0)		677	677	0	
Interest Expense	153	154	0		153	154	1	
Income from Ongoing Operations before income taxes	524	524	0		524	523	1	
Income Tax Expense	196	196	(0)		196	195	(1)	
Net Income (loss) from ongoing operations	**328**	**328**	**(0)**		**328**	**328**	**0**	
Non Operating Income	1	-	1		1	0	0	
Discontinued Operations	1	(1)	3		1	(1)	2	
Net Income (loss)	$ 329	$ 326	$ 3		$ 329	$ 327	$ 2	
KY Regulated Financing Costs	(41)	(37)	(4)	Higher due to revised rates and durations of remarketing of the 2010 Equity Units.	(41)	(37)	(4)	Higher due to revised rates and durations of remarketing of the 2010 Equity Units.
KY Regulated Net Income	$ 289	$ 289	$ (1)		$ 289	$ 291	$ (2)	
Earnings Per Share	$ 0.46	$ 0.46	$ 0.00		$ 0.46	$ 0.47	$ (0.01)	

Electric Gross Margin

June 2013

($ Millions)

	MTD						YTD					
	Actual	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**	**Actual**	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**
Base Electric Margin:						**$ (9)** ◆						**$ (17)** ◆
Energy Volumes (a)	2,779,691	2,984,629	(205)	$ -	$ (5)		16,254,320	16,363,664	(109)	$ -	$ (2)	
Energy Prices (a)					0						(3)	
Customer Charges (Avg. Customers)	935,174	945,266	(10,092)		-		935,411	944,302	(8,891)		1	
Demand Charges (b)					(4)						(14)	
ECR:						**(0)** ◆						**(1)** ◆
Average Rate Base	$ 683	$ 794	$ (0)	10.44%	$ (0.9)		$ 589	$ 670	$ (0)	10.44%	$ (3.8)	
Cost of Capital	10.23%	10.44%	-0.21%	$ 683	(0.1)		10.31%	10.44%	-0.13%	$ 589	(0.3)	
Jurisdictional Factor	89.09%	89.85%	-0.76%	$ 683	-		88.33%	88.31%	0.03%	$ 589	-	
Other					0.7						2.7	
DSM:						**1** ●						**4** ●
Program Expense (Revenue Net of Expense)	$ (0.1)	$ (0.3)			$ 0.2		$ (0.1)	$ (1.4)			$ 1.3	
Lost Sales	0.9	1.0			(0.1)		8.0	6.1			1.9	
Incentive	0.1	0.1			-		0.6	0.4			0.2	
Balancing Adjustment	0.6	-			0.6		0.2	-			0.2	
Net Fuel Recovery	$ (0.7)	$ (0.8)				**0** ●	$ 1	$ (3)				**4** ●
Purchase Power Demand						**0** ●						**0** ●
Transmission						**1** ●						**-** ●
Other						**-** ●						**(0)** ◆
Retail Margin Variance						**(7)** ◆						**(11)** ◆
Off-System Margin Variance						**1** ●						**-** ●
Electric Margin Variance						**$ (6)** ◆						**$ (11)** ◆

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 43	879,629	$ 49.09	$ 44	897,786	$ 49.15	$ (1) ◆	$ (1) ◆	$ (0) ◆
Commercial	20	645,940	31.39	23	740,910	31.18	(3) ◆	(3) ◆	0 ●
Industrial	8	852,750	9.06	8	899,999	8.91	(0) ◆	(0) ◆	0 ●
Municipals	1	163,892	4.68	1	180,614	4.69	- ●	(0) ◆	- ●
Other	5	237,480	22.21	6	265,320	22.73	(1) ◆	(1) ◆	(0) ◆
Native Load Total	**$ 77**	**2,779,691**	**$ 27.78**	**$ 82**	**2,984,629**	**$ 27.51**	**$ (5)** ◆	**$ (5)** ◆	**$ 0** ●

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 260	5,362,469	$ 48.48	$ 256	5,305,192	$ 48.37	$ 4 ●	$ 3 ●	$ 1 ●
Commercial	120	3,764,742	31.79	124	3,883,273	32.05	(5) ◆	(4) ◆	(1) ◆
Industrial	42	4,835,885	8.66	43	4,828,465	8.81	(1) ◆	0 ●	(1) ◆
Municipals	4	928,829	4.68	4	933,190	4.69	- ●	- ●	- ●
Other	30	1,362,396	21.68	33	1,413,544	23.42	(4) ◆	(1) ◆	(2) ◆
Native Load Total	**$ 456**	**16,254,320**	**$ 28.02**	**$ 461**	**16,363,664**	**$ 28.18**	**$ (5)** ◆	**$ (2)** ◆	**$ (3)** ◆

(b) Demand Analysis (net of base ECR revenue):	MTD			YTD		
$mil	**Act**	**Bud**	**Variance**	**Act**	**Bud**	**Variance**
Commercial	14	17	(2)	76	82	(6)
Industrial	17	19	(2)	96	102	(6)
Municipals	4	5	(0)	23	26	(3)
Other	6	6	1	32	30	2
Native Load Total	**43**	**46**	**(4)**	**226**	**240**	**(14)**

Weather Statistics	MTD			YTD		
	Act	**+/- Bud**		**Act**	**+/- Bud**	
Heating Degree Days - Louisville	0	(6)	-100%	2,734	130	5%
Heating Degree Days - Lexington	0	(10)	-100%	2,892	55	2%
Cooling Degree Days - Louisville	297	(3)	-1%	483	30	7%
Cooling Degree Days - Lexington	269	30	13%	421	73	21%

Gas Gross Margin

June 2013

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**$ -** 🟢	**$ 33**	**$ 30**		**$ 3** 🟢
Gas Supply Costs								
Gas Supply Costs	(4)	(3)	$ (1)		(93)	(90)	$ (3)	
GSC Revenue	4	3	1		94	92	2	
Net Gas Supply Costs				**0** 🟢				**(1)** ♦
Retail Gas (a)	**3**	**2**		**0** 🟢	**53**	**50**		**3** 🟢
Wholesale Gas (a)	**-**	**-**		**-** 🟢	**-**	**-**		**-** 🟢
DSM	**(1)**	**(0)**		**(1)** ♦	**-**	**(1)**		**1** 🟢
GLT	**0**	**0**		**(0)** ♦	**1**	**1**		**-** 🟢
WNA	**-**	**-**		**-** 🟢	**(3)**	**-**		**(3)** ♦
Other Margin	**0**	**0**		**(0)** ♦	**1**	**2**		**(1)** ♦
Gas Margin Variance				**$ (1)** ♦				**$ 1** 🟢

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 1	408,812	$ 2.63	$ 1	432,212	$ 2.68	$ (0) ♦	$ (0) ♦	$ - 🟢
Commercial	1	266,359	1.93	1	249,217	2.07	- 🟢	- 🟢	- 🟢
Industrial	0	78,305	1.52	0	42,299	1.78	- 🟢	0 🟢	- 🟢
Public Authority	-	23,196	1.82	0	33,658	1.79	(0) ♦	- 🟢	- 🟢
Transportation	1	714,663	0.99	0	623,279	0.42	0 🟢	- 🟢	0 🟢
Ultimate Consumer	$ 3	1,491,335	$ 1.65	$ 2	1,380,665	$ 1.50	$ 0 🟢	$ 0 🟢	$ 0 🟢

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 34	12,684,312	$ 2.64	$ 33	12,758,023	$ 2.58	$ 1 🟢	$ (0) ♦	$ 1 🟢
Commercial	11	5,394,988	2.04	11	5,441,631	2.05	(0) ♦	(0) ♦	(0) ♦
Industrial	1	626,813	1.73	1	515,810	1.85	0 🟢	0 🟢	(0) ♦
Public Authority	2	981,100	1.97	2	999,759	1.97	(0) ♦	- 🟢	- 🟢
Transportation	5	6,446,024	0.81	3	6,188,492	0.45	3 🟢	0 🟢	2 🟢
Ultimate Consumer	$ 53	26,133,237	$ 2.02	$ 50	25,903,715	$ 1.92	$ 3 🟢	$ - 🟢	$ 3 🟢

O&M	**June 2013**

($ Millions)

	MTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 15	$ 17	$ 2	$ -	$ 0	$ 0	$ 1	$ 1	$ -	$ 1
Project Engineering	0	0	0	-	$ 0	-	(0)	(0)	-	0
Transmission	3	3	(0)	-	$ (0)	-	(0)	0	-	0
Energy Supply and Analysis	1	1	0	-	$ (0)	-	0	0	-	0
Electric Distribution	5	5	0	-	$ (0)	-	0	0	(0)	0
Gas Distribution	2	3	0	-	$ (0)	-	0	0	0	(0)
Customer Services	7	7	1	-	$ 0	-	0	0	1	(0)
Chief Operations Officer	**33**	**36**	**3**	**-**	**(0)**	**0**	**2**	**1**	**1**	**0**
Information Technology	4	4	0	-	0	-	0	(0)	-	(0)
General Counsel	3	3	0	-	(0)	-	0	(0)	-	0
Human Resources	0	1	0	-	0	-	0	0	-	0
Supply Chain	0	0	0	-	(0)	-	0	0	-	0
Chief Administrative Officer	**7**	**8**	**0**	**-**	**0**	**-**	**1**	**(0)**	**-**	**(0)**
Chief Financial Officer	**1**	**2**	**0**	**-**	**0**	**-**	**(0)**	**0**	**-**	**0**
Corporate	**10**	**12**	**3**	**2**	**0**	**-**	**0**	**0**	**(0)**	**0**
O&M Total MTD	**$ 52**	**$ 58**	**$ 6**	**$ 2**	**$ (0)**	**$ 0**	**$ 3**	**$ 1**	**$ 1**	**$ 1**

	YTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 111	$ 116	$ 4	$ -	$ 3	$ 5	$ 1	$ 0	$ -	$ (5)
Project Engineering	0	0	0	-	0	-	(0)	(0)	-	0
Transmission	15	15	0	-	(0)	-	0	0	-	(0)
Energy Supply and Analysis	4	5	1	-	0	-	0	0	-	0
Electric Distribution	34	34	1	-	(0)	-	(0)	0	(0)	1
Gas Distribution	15	16	1	-	0	-	1	(0)	(0)	0
Customer Services	38	44	6	-	2	-	1	0	3	(0)
Chief Operations Officer	**218**	**231**	**12**	**-**	**4**	**5**	**3**	**1**	**3**	**(4)**
Information Technology	24	24	0	-	1	-	(1)	(0)	-	0
General Counsel	14	16	1	-	0	-	1	0	-	(0)
Human Resources	3	3	0	-	(0)	-	0	0	-	0
Supply Chain	2	2	0	-	0	-	0	0	-	0
Chief Administrative Officer	**43**	**45**	**2**	**-**	**1**	**-**	**0**	**(0)**	**-**	**1**
Chief Financial Officer	**9**	**9**	**1**	**-**	**0**	**-**	**(0)**	**0**	**-**	**1**
Corporate	**76**	**73**	**(3)**	**(4)**	**(0)**	**-**	**2**	**1**	**0**	**(2)**
O&M Total YTD	**$ 346**	**$ 358**	**$ 12**	**$ (4)**	**$ 5**	**$ 5**	**$ 5**	**$ 1**	**$ 4**	**$ (4)**

	Full Year			Variances						
	Forecast	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 225	$ 227	$ 2	$ -	$ 3	$ 1	$ (0)	$ (3)	$ -	$ 1
Project Engineering	1	1	0	-	(0)	-	(0)	(0)	-	0
Transmission	29	29	0	-	(0)	-	2	(2)	-	(0)
Energy Supply and Analysis	9	10	1	-	0	-	0	0	-	0
Electric Distribution	68	69	1	-	(1)	-	1	1	-	(0)
Gas Distribution	33	34	0	-	(0)	-	1	0	-	(1)
Customer Services	87	91	4	-	2	-	1	(0)	3	(2)
Chief Operations Officer	**452**	**461**	**9**	**-**	**4**	**1**	**5**	**(3)**	**3**	**(2)**
Information Technology	50	50	1	-	2	-	(1)	-	-	0
General Counsel	32	34	3	-	0	-	2	-	-	0
Human Resources	7	7	0	-	0	-	0	(0)	-	(0)
Supply Chain	3	3	0	-	(0)	-	0	-	-	0
Chief Administrative Officer	**91**	**95**	**4**	**-**	**2**	**-**	**2**	**(0)**	**-**	**0**
Chief Financial Officer	**18**	**19**	**1**	**-**	**0**	**-**	**0**	**-**	**-**	**1**
Corporate	**142**	**146**	**4**	**(5)**	**(1)**	**-**	**1**	**(1)**	**0**	**8**
O&M Total Full Year	**$ 704**	**$ 721**	**$ 17**	**$ (5)**	**$ 6**	**$ 1**	**$ 8**	**$ (4)**	**$ 3**	**$ 7**

Financing Activities June 2013

($ Millions)

	MTD			YTD			Full Year		
Balance Sheet	**Actual**	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**	**Forecast**	**Budget**	**Variance**
PCB									
Beg Bal	$ 931.9	$ 931.9	$ -	$ 932.0	$ 932.0	$ 0.0	$ 932.0	$ 932.0	$ -
End Bal	931.8	931.8	-	931.8	931.8	-	931.7	931.7	-
Ave Bal	**$ 931.9**	**$ 931.9**	**$ -**	**$ 931.9**	**$ 931.9**	**$ (0.0)**	**$ 931.8**	**$ 931.8**	**$ -**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 5.2**	**$ 6.8**	**$ 1.6**	**$ 12.0**	**$ 13.6**	**$ 1.6**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.12%**	**1.46%**	**0.34%**	**1.29%**	**1.46%**	**0.17%**
FMB/Sr Nts									
Beg Bal	$ 3,143.5	$ 3,143.5	$ (0.0)	$ 3,142.8	$ 3,142.8	$ 0.0	$ 3,142.8	$ 3,142.8	$ 0.0
End Bal	3,143.6	3,143.6	(0.0)	3,143.6	3,143.6	(0.0)	3,644.4	3,694.4	50.0
Ave Bal	**$ 3,143.5**	**$ 3,143.5**	**$ (0.0)**	**$ 3,143.2**	**$ 3,143.3**	**$ 0.1**	**$ 3,227.0**	**$ 3,235.3**	**$ 8.3**
Interest Exp	**$ 9.6**	**$ 9.6**	**$ 0.0**	**$ 57.3**	**$ 57.3**	**$ (0.0)**	**$ 120.3**	**$ 120.2**	**$ (0.1)**
Rate	**0.00%**	**0.00%**	**0.00%**	**3.63%**	**3.63%**	**0.00%**	**3.73%**	**3.72%**	**-0.01%**
Short-term Debt									
Beg Bal	$ 320.7	$ 411.7	$ 91.0	$ 149.7	$ 149.7	$ (0.0)	$ 149.7	$ 149.7	$ (0.0)
End Bal	324.8	418.4	93.6	324.8	418.4	93.6	210.0	176.3	(33.7)
Ave Bal	**$ 322.7**	**$ 415.0**	**$ 92.3**	**$ 237.2**	**$ 310.6**	**$ 73.3**	**$ 329.2**	**$ 359.0**	**$ 29.8**
Interest Exp	**$ 0.2**	**$ 0.2**	**$ 0.0**	**$ 1,149.8**	**$ 1,081.6**	**$ (68.2)**	**$ 2.5**	**$ 1.2**	**$ (1.3)**
Rate	**0.00%**	**0.00%**	**0.00%**	**0.96%**	**0.69%**	**-0.27%**			
Total End Bal	**$ 4,400.2**	**$ 4,493.8**	**$ 93.6**	**$ 4,400.2**	**$ 4,493.8**	**$ 93.6**	**$ 4,786.1**	**$ 4,802.4**	**$ 16.3**
Total Average Bal	**$ 4,398.1**	**$ 4,490.4**	**$ 92.3**	**$ 4,312.3**	**$ 4,385.7**	**$ 73.4**	**$ 4,488.1**	**$ 4,526.2**	**$ 38.1**
Total Expense Excl I/C	**$ 12.3**	**$ 12.5**	**$ 0.2**	**$ 74.2**	**$ 74.9**	**$ 0.7**	**$ 153.5**	**$ 153.8**	**$ 0.4**
Rate	**3.59%**	**3.59%**	**0.00%**	**3.42%**	**3.40%**	**-0.02%**	**3.42%**	**3.40%**	**-0.02%**

Credit Facilities ($ Millions)	**Committed Capacity**	**Borrowed**	**Letters of Credit Issued**	**Unused Capacity**
LKE	$ 300	$ 72		$ 228
LG&E	500	80		420
KU	598	172	$ 198	228
TOTAL	$ 1,398	$ 324	$ 198	$ 876

Credit Metrics	**YTD**		**Full Year**	
($ Millions)	**Actual**	**+/- Bud**	**Forecast**	**+/- Bud**
FFO to Debt - LG&E	32.5%	+0.04	27.8%	+0.01
FFO to Debt - KU	27.3%	+0.01	25.4%	-0.00
Debt to EBITDA - LG&E (1)	2.85	-0.46	3.24	-0.08
Debt to EBITDA - KU (1)	3.76	+0.10	3.68	+0.02
Debt to Capitalization - LG&E (2)	44.1%	-0.01	46.7%	-0.00
Debt to Capitalization - KU (2)	46.5%	-0.01	47.0%	+0.00

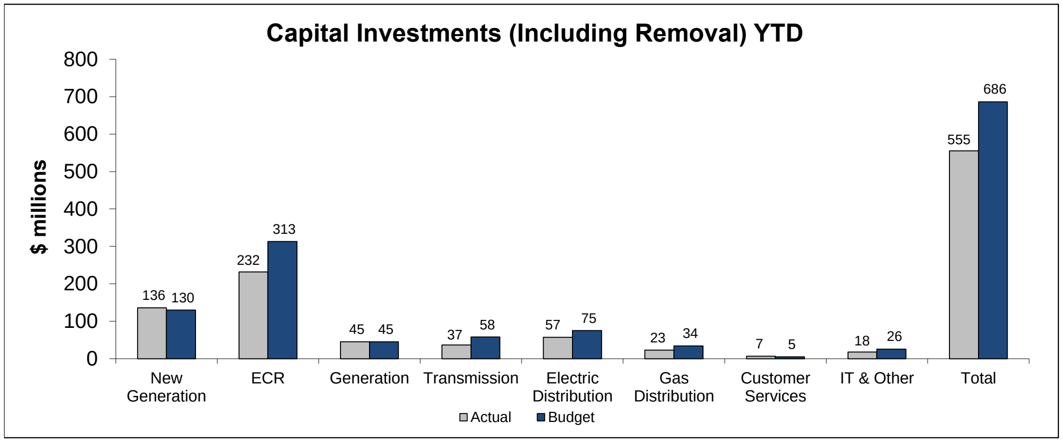
(1) Actuals represent a trailing 12 months

(2) Excludes purchase accounting adjustments and corresponding goodwill of $996m

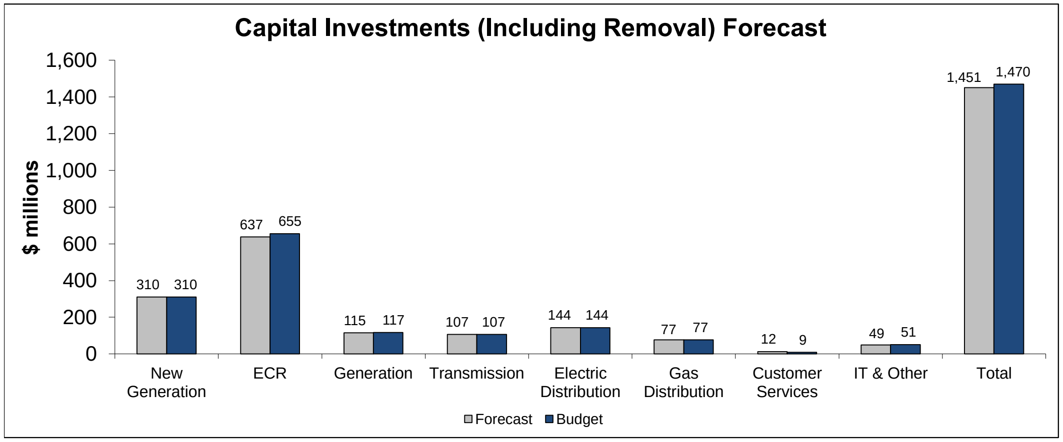
Balance Sheet June 2013

($ Millions)

	YTD	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 23	$ 10	$ 14	See cash flow chart for details.
Accounts Receivable (Trade)	365	324	41	Due primarily to tariff rate variance in receivable logic and extended due date granted in rate case.
Inventory	251	230	20	Increase in fuel ($13m), gas ($3m) and materials and supplies ($4m).
Deferred Income Taxes	11	13	(3)	
Prepayments and other current assets	119	70	49	Primarily due to short-term derivative asset gain from forward hedges entered into in November 2012 with PPL as counterparty as a result of an increase in market interest rates ($57m).
Total Current Assets	768	647	121	
Property, Plant, and Equipment	8,701	8,832	(130)	See capital chart for details.
Intangible Assets	245	246	(1)	
Other Property and Investments	1	1	0	
Regulatory Assets	609	635	(27)	Due to interest rate swaps ($15m) and decrease in FAC ($12m).
Goodwill	997	997	-	
Other Long-term Assets	97	104	(8)	
Total Assets	**$ 11,418**	**$ 11,462**	**$ (44)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 302	$ 226	$ 76	Primarily differences in capex accrual and an increase in retainage fees and fuel volumes.
Accounts Payable - Affiliated Company	(0)	(0)	0	
Customer Deposits	49	48	1	
Derivative Liability	4	5	(1)	
Accrued Taxes	26	20	6	
Other Current Liabilities	125	110	15	Due primarily to timing of outstanding checks and cash funding ($16m).
Total Current Liabilities	507	409	98	
Debt - Affiliated Company	-	-	-	
Debt	4,400	4,494	(94)	Less short-term debt issued than budgeted ($141m) due to lower capital spend, offset by notes payable to PPL ($48m). See Financing Activities page for more details.
Total Debt	4,400	4,494	(94)	
Deferred Tax Liabilities	637	655	(18)	Timing of recording of deferred taxes in actuals vs. budget.
Investment Tax Credit	137	136	1	
Accumulated Provision for Pension and Related Benefits	266	269	(3)	
Asset Retirement Obligation	127	128	(1)	
Regulatory Liabilities	1,045	997	48	Primarily due to short-term derivative asset gain from forward hedges entered into in November 2012 with PPL as counterparty as a result of an increase in market interest rates ($57m).
Derivative Liability	39	54	(14)	Increase in interest rate swaps with non-related third parties due to an increase in market interest rates causing a decrease in the derivative liability.
Other Liabilities	240	239	0	
Total Deferred Credits and Other Liabilities	2,490	2,478	12	
Equity	4,021	4,081	(60)	
Total Liabilities and Equity	**$ 11,418**	**$ 11,462**	**$ (44)**	



Capital was $131m lower than budget due mainly to slower than expected mobilization for Mill Creek ($32m) and Ghent ($24) environmental air work. Differences on Ghent and Brown landfill projects ($15m) and other environmental projects ($9m) are expected to reverse by year end. Transmission underspend ($21m) was mainly due to delayed spending on Cane Run 7, New Albany transmission work and line rating projects; Distribution variances ($29m) were driven by timing of circuit hardening, major substation projects, main replacement and gas riser projects.



Capital is projected to be $19m lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.

Cash Flow

June 2013

YTD	Actual	Budget	Variance	Comments
Net income	160	151	9	
Depreciation	179	175	4	
Deferred tax expense	95	110	-15	Differences in how annual estimates are spread in actuals vs. budget.
Other Balance Sheet Movements	-134	-196	62	Includes increases in credit cash balance and accrued taxes, as well as decreases in regulatory assets and deferred tax assets.
Funds From Operations	**300**	**240**	**60**	
Changes in accounts receivables	-72	-31	-41	Tariff rate variance in receivable logic, extended due date granted in rate case.
Changes in inventories	25	43	-18	Increase in fuel prices.
Changes in accounts payable	44	39	4	
Change in Working Capital	**-3**	**52**	**-55**	
Operating Cash flow	**297**	**292**	**5**	
Capex	-579	-739	160	See Capex Charts for details.
Other Investing	11	0	11	
Loans to Affiliates	0	0	0	
Investing Cash flow	**-568**	**-739**	**171**	
Dividends	-69	-42	-27	Higher dividends and lower equity infusions due to lower capital spend projected than budgeted.
Equity Infusion	146	187	-41	Higher dividends and lower equity infusions due to lower capital spend projected than budgeted.
Net Borrowings	174	269	-95	Higher dividends and lower equity infusions due to lower capital spend projected than budgeted.
Other	0	0	0	
Financing Cash flow	**251**	**414**	**-122**	
Net increase (decrease) in cash	**-20**	**-34**	**54**	

Full Year	FC	Budget	Variance	Comments
Net income	329	326	3	
Depreciation, amortization and impairments	354	356	-2	
Deferred tax expense	214	178	36	Differences in YTD actual deferred taxes vs. budget.
Other Balance Sheet Movements	-131	-204	73	Includes increases in credit cash balance and accrued taxes, as well as decreases in regulatory assets and deferred tax assets.
Funds From Operations	**766**	**656**	**110**	
Changes in accounts receivables	-156	-35	-121	Tariff rate variance in receivable logic, extended due date granted in rate case.
Changes in inventories	-2	15	-17	
Changes in accounts payable	166	113	53	Differences in capex accrual.
Change in Working Capital	**9**	**94**	**-85**	
Operating Cash flow	**774**	**750**	**25**	
Capex	-1,510	-1,576	66	Revised cash adjustment ($47m) and delay in Trimble County landfill to 2015 ($12m).
Other Investing	10	0	10	
Loans to Affiliates	0	0	0	
Investing Cash flow	**-1,500**	**-1,576**	**76**	
Dividends	-154	-157	3	
Equity Infusion	318	374	-56	Lower equity infusions and debt due to lower capital spend projected than budgeted.
Net Borrowings	528	577	-48	Lower equity infusions and debt due to lower capital spend projected than budgeted.
Other	0	0	0	
Financing Cash flow	**692**	**793**	**-45**	
Net increase (decrease) in cash	**-34**	**-33**	**56**	

Performance Report

July 2013

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Kentucky Regulated Dashboard

July 2013

Operational Metrics	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	2.47	2.12	1.52	1.66	N/A	1.35
Employee lost-time incidents	0	0	0	4	N/A	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,117	3,455	19,926	20,617	34,774	35,128
Utility EFOR	8.1%	5.1%	8.1%	5.1%	N/A	5.1%
Utility EAF	88.3%	92.3%	80.2%	87.3%	N/A	87.08%
Combined SAIFI	0.12	0.17	0.61	0.77	N/A	1.22
Combined SAIDI (minutes)	9.30	17.61	56.22	72.31	N/A	109.60
GwH Sales						
Residential	1,024	1,146	6,388	6,451	10,904	10,912
Commercial	739	795	4,504	4,678	7,858	8,063
Industrial	797	896	5,633	5,725	9,949	9,891
Municipals	173	194	1,102	1,127	1,904	1,944
Other	250	272	1,613	1,686	2,791	2,901
Off-System Sales	53	4	283	320	380	465
Total	3,037	3,306	19,523	19,987	33,785	34,175
Weather-Normalized Sales Growth(1)			**W-N**			
Residential			0.45%			
Commercial			-1.36%			
Industrial			2.30%			
Other(2)			-1.38%			
Total			0.28%			

Variance Explanations

- The generation fleet's EAF and EFOR are unfavorable YTD to budget due to temperature and balance issues on Ghent U4 ID fan bearing; turbine bearing failure, air heater pluggage and start-up failure generator lockout on Trimble County U2; hydrogen seal leak and damaged bearing on Mill Creek U4; damaged boiler corner support hangers on Brown U3; air heater fouling on Ghent U3 & U4; winding shorts on generator rotor on Cane Run U4; and cooling tower distribution header failure on Ghent U4.
- Lower margins due primarily to $16 million of lower electric energy revenues driven by mild weather and $18 million of lower electric demand charge revenues, offset by $10 million favorable margins on other retail rate mechanisms and $2 million favorable gas margins.
- Capital was $26 million lower than budget in July due mainly to revised schedules for Mill Creek of $5 million and delay in Trimble County landfill to 2015 of $6 million. Timing of distribution capital spend driven partly by priority pipeline and gas riser replacements are not expected to cause full-year distribution variances.
- Capital was $157 million lower than budget YTD due mainly to slower than expected mobilization for Mill Creek of $37 million and Ghent environmental air work of $24 million. Spending delays on Ghent and Brown landfill projects of $14 million and other environmental projects of $6 million are expected to reverse by year end. Transmission underspend of $23 million was due mainly to delayed spending on Cane Run U7, New Albany transmission work and line rating projects; Distribution variances of $34 million were driven by timing of circuit hardening, major substation projects, main replacement and gas riser projects.
- Full year capital is projected to be $19 million lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE(3)	11.9%	13.5%	10.1%	10.0%	9.5%	9.6%
Electric Margins	$148	$160	$924	$948	$1,600	$1,638
Gas Margins	$8	$8	$96	$94	$157	$156
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$30	$31	$166	$161	$310	$310
ECR	43	53	275	366	637	655
Generation	8	12	53	57	115	117
Transmission	5	7	42	65	107	107
Electric Distribution	9	13	67	88	144	144
Gas Distribution	7	9	30	43	77	77
Customer Services	1	1	7	6	12	9
IT and Other	2	5	20	31	49	51
Total	$105	$131	$660	$817	$1,451	$1,470
O&M ($ millions)(4)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$36	$38	$254	$268	$450	$461
Administrative	$6	8	$49	$53	90	95
Finance and Accounting	$2	2	$10	$11	18	19
Corp Burdens & Other Charges	$12	12	$88	$85	142	146
Total	$56	$59	$401	$417	$700	$721
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,344	3,432	3,344	3,432	3,435	3,435
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	1	3	4	5	N/A	14
NERC Possible Violations(5)	0	0	7	8	N/A	29

Major Developments

- In Louisville and Lexington, July 2013 ranked as the 3rd and 5th coolest, respectively, in the past 20 years. The extremely mild summer weather has continued during the first half of August.
- Louisville millionaire and tea party favorite Matthew Bevin entered Kentucky's U.S. Senate race, setting up a Republican primary race with Minority Leader Mitch McConnell. The winner will face Democrat Alison Lundergan Grimes.
- The Kentucky Division for Air Quality released their audit findings of the Louisville Air Pollution Control District's ambient air particulate monitoring program. The audit findings were extensive including a statement that "the staff lacked an understanding of their responsibilities and the mathematics and scientific principles upon which air-monitoring programs are implemented." EPA will now review the audit report and determine whether to accept the air monitoring data. Since the Air District had hoped to use this data to demonstrate that the county was in attainment, the county status is now in question.

Significant Future Events

- LG&E and KU continue to evaluate responses received from their request for proposals for up to 700 MW of capacity beginning as early as 2015 as well as self-build alternatives. A decision on market opportunities versus self-build options is expected in Q3 and will be incorporated into the 2014-2018 business plan.

(1) Percentages represent a trailing twelve months.

(2) "Other" is typically comprised of the public authority customer class and KU's 12 full-requirements wholesale municipal customers.

(3) Excludes goodwill and other purchase accounting adjustments.

(4) Net of cost recovery mechanisms.

(5) The seven NERC Possible Violation Issues for YTD Actual are expected to be resolved through NERC's Find, Fix and Track ("FFT") process without financial penalty.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget and Forecast (Month)

July 2013

($ Millions)

	MTD				MTD			
	Actual	**Budget**	**Variance**	**Comments**	**Actual**	**Q2 Forecast**	**Variance**	**Comments**
Revenues:								
Electric Revenues	$ 246	$ 272	$ (26)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.	$ 246	$ 264	$ (19)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.
Gas Revenues	12	12	1		12	13	(1)	
Total Revenues	258	284	(26)		258	278	(20)	
Cost of Sales:								
Fuel Electric Costs	85	95	10	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.	85	95	10	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.
Gas Supply Expenses	4	4	(0)		4	5	1	
Purchased Power	4	6	1		4	6	2	
Other Electric Cost	8	11	2		8	6	(2)	
Total Cost of Sales	102	115	14		102	112	11	
Gross Margin:								
Electric Margin	148	160	(12)	Primarily $11m of lower electric energy revenues as volumes were down 10% due to unseasonably mild weather and economic conditions.	148	157	(9)	Lower electric energy volumes due to unseasonably mild weather and economic conditions.
Gas Margin	8	8	0		8	8	0	
Total Gross Margin	156	168	(12)		156	166	(9)	
Operating Expenses:								
O&M	56	59	3		56	60	4	
Depreciation & Amortization	27	28	1		27	27	(0)	
Taxes, Other than Income	4	4	0		4	4	0	
Total Operating Expenses	87	91	4		87	92	4	
Equity in earnings	-	(0)	0		-	0	(0)	
Other income	(0)	(1)	0		(0)	(0)	(0)	
EBIT	69	77	(8)		69	73	(4)	
Interest Expense	12	13	0		12	13	0	
Income from Ongoing Operations before income taxes	57	64	(8)		57	61	(4)	
Income Tax Expense	21	24	3		21	23	2	
Net Income (loss) from ongoing operations	**35**	**40**	**(4)**		**35**	**38**	**(2)**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	(0)	(0)	0		(0)	0	(0)	
Net Income (loss)	$ 35	$ 40	$ (4)		$ 35	$ 38	$ (2)	
KY Regulated Financing Costs	(3)	(2)	(0)		(3)	(3)	0	
KY Regulated Net Income	$ 33	$ 37	$ (5)		$ 33	$ 35	$ (2)	
Earnings Per Share	$ 0.05	$ 0.06	$ 0.00		$ 0.05	$ 0.05	$ 0.01	

Income Statement: Actual vs. Budget (YTD) July 2013

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,550	$ 1,593	$ (43)	Primarily $16m of lower electric energy volumes driven by unseasonably mild weather and economic conditions and $18m of lower electric demand charge revenues.
Gas Revenues	193	191	2	
Total Revenues	1,743	1,783	(41)	
Cost of Sales:				
Fuel Electric Costs	535	544	10	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.
Gas Supply Expenses	97	97	(0)	
Purchased Power	34	38	3	
Other Electric Cost	57	63	6	Lower electric volumes and ECR costs.
Total Cost of Sales	724	742	19	
Gross Margin:				
Electric Margin	924	948	(24)	Primarily $16m of lower electric energy volumes driven by unseasonably mild weather and economic conditions and $18m of lower electric demand charge revenues, offset by $10m favorable margins on other retail rate mechanisms.
Gas Margin	96	94	2	
Total Gross Margin	1,020	1,042	(22)	
Operating Expenses:				
O&M	401	417	16	Related to $4m of lower outside services, $4m of lower uncollectible accounts and $7m of labor savings.
Depreciation & Amortization	191	196	5	
Taxes, Other than Income	28	28	0	
Total Operating Expenses	620	641	21	
Equity in earnings	-	(1)	1	
Other income	(5)	(6)	1	
EBIT	394	394	0	
Interest Expense	87	87	1	
Income from Ongoing Operations before income taxes	308	307	1	
Income Tax Expense	115	115	(0)	
Net Income (loss) from ongoing operations	**193**	**192**	**1**	
Non Operating Income	1	-	1	
Discontinued Operations	2	(1)	3	
Net Income (loss)	$ 195	$ 191	$ 4	
KY Regulated Financing Costs	(28)	(25)	(3)	
KY Regulated Net Income	$ 168	$ 166	$ 1	
Earnings Per Share	$ 0.27	$ 0.28	$ (0.01)	

Income Statement: Forecast vs. Budget and Prior Forecast

July 2013

($ Millions)

	Full Year				Full Year			
	Forecast	**Budget**	**Variance**	**Comments**	**Forecast**	**Q2 Forecast**	**Variance**	**Comments**
Revenues:								
Electric Revenues	$ 2,687	$ 2,753	$ (65)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.	$ 2,687	$ 2,706	$ (19)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.
Gas Revenues	314	313	2		314	315	(1)	
Total Revenues	3,002	3,065	(64)		3,002	3,021	(20)	
Cost of Sales:								
Fuel Electric Costs	918	928	10	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.	918	928	10	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.
Gas Supply Expenses	157	157	0		157	158	1	
Purchased Power	64	67	3		64	66	2	
Other Electric Cost	105	119	14	Lower electric volumes.	105	103	(2)	
Total Cost of Sales	1,244	1,271	27		1,244	1,255	11	
Gross Margin:								
Electric Margin	1,600	1,638	(38)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.	1,600	1,609	(9)	Lower electric energy volumes due to unseasonably mild weather in July and economic conditions.
Gas Margin	157	156	1		157	157	-	
Total Gross Margin	1,757	1,794	(37)		1,757	1,766	(9)	
Operating Expenses:								
O&M	700	721	21	Favorable labor and burdens ($7m), uncollectible accounts ($4m), outside services ($5m) and materials ($5m).	700	704	4	
Depreciation & Amortization	329	338	9	Revised estimates based on delayed capital spend in 2012 and revised in-service dates for capital projects in 2013.	329	329	-	
Taxes, Other than Income	48	48	(0)		48	48	-	
Total Operating Expenses	1,078	1,107	30		1,078	1,082	4	
Equity in earnings	0	(1)	1		0	0	-	
Other income	(7)	(8)	1		(7)	(7)	-	
EBIT	673	677	(4)		673	677	(4)	
Interest Expense	153	154	0		153	153	(0)	
Income from Ongoing Operations before income taxes	520	524	(4)		520	524	(4)	
Income Tax Expense	194	196	2		194	196	2	
Net Income (loss) from ongoing operations	**326**	**328**	**(2)**		**326**	**328**	**(2)**	
Non Operating Income	0	-	0		0	1	(0)	
Discontinued Operations	0	(1)	2		0	1	(1)	
Net Income (loss)	$ 327	$ 326	$ 0		$ 325	$ 329	$ (5)	
KY Regulated Financing Costs	(41)	(37)	(4)		(41)	(40)	(1)	
KY Regulated Net Income	$ 286	$ 289	$ (3)		$ 285	$ 289	$ (4)	
Earnings Per Share	$ 0.45	$ 0.46	$ (0.01)		$ 0.45	$ 0.46	$ (0.01)	

Electric Gross Margin — July 2013

($ Millions)

	MTD						YTD					
	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance
Base Electric Margin:						$ (15) ◆						$ (34) ◆
Energy Volumes (a)	2,983,768	3,302,728	(319)	$ -	$ (9)		19,238,089	19,666,392	(428)	$ -	$ (11)	
Energy Prices (a)					(2)						(6)	
Customer Charges (Avg. Customers)	934,597	946,711	(12,114)		-		935,295	944,646	(9,351)		1	
Demand Charges (b)					(4)						(18)	
ECR:						(1) ◆						(2) ◆
Average Rate Base	$ 725	$ 838	$ (0)	10.43%	$ (0.9)		$ 608	$ 694	$ (0)	10.44%	$ (4.6)	
Cost of Capital	10.25%	10.43%	-0.19%	$ 725	(0.1)		10.30%	10.44%	-0.14%	$ 608	(0.4)	
Jurisdictional Factor	89.88%	89.80%	0.08%	$ 725	-		88.60%	88.57%	0.03%	$ 608	-	
Other					-						3.4	
DSM:						1 ●						5 ●
Program Expense (Revenue Net of Expense)	$ 0.5	$ (0.5)			$ 1.0		$ 0.5	$ (2.0)			$ 2.5	
Lost Sales	1.1	1.0			0.1		9.1	7.1			2.0	
Incentive	0.1	0.1			-		0.7	0.4			0.3	
Balancing Adjustment	0.3	-			0.3		0.5	-			0.5	
Net Fuel Recovery	$ (0.3)	$ (0.5)				0 ●	$ 1	$ (4)				5 ●
Purchase Power Demand						1 ●						1 ●
Transmission						0 ●						0 ●
Other						0 ●						0 ●
Retail Margin Variance						(13) ◆						(25) ◆
Off-System Margin Variance						1 ●						1 ●
Electric Margin Variance						$ (12) ◆						$ (24) ◆

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 50	1,024,208	$ 48.77	$ 56	1,145,750	$ 49.09	$ (6) ◆	$ (6) ◆	$ (0) ◆
Commercial	23	739,452	30.80	26	794,994	32.33	(3) ◆	(2) ◆	(1) ◆
Industrial	7	797,146	8.56	8	896,397	8.99	(1) ◆	(1) ◆	(0) ◆
Municipals	1	172,800	5.56	1	193,956	4.69	0 ●	(0) ◆	0 ●
Other	5	250,162	20.72	6	271,631	22.82	(1) ◆	(1) ◆	(1) ◆
Native Load Total	**$ 86**	**2,983,768**	**$ 28.72**	**$ 97**	**3,302,728**	**$ 29.40**	**$ (11)** ◆	**$ (9)** ◆	**$ (2)** ◆

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 310	6,386,677	$ 48.52	$ 312	6,450,943	$ 48.50	$ (2) ◆	$ (2) ◆	$ 0 ●
Commercial	142	4,504,194	31.63	150	4,678,267	32.09	(8) ◆	(6) ◆	(2) ◆
Industrial	49	5,633,031	8.65	51	5,724,862	8.84	(2) ◆	(1) ◆	(1) ◆
Municipals	5	1,101,629	4.82	5	1,127,146	4.69	- ●	(0) ◆	0 ●
Other	35	1,612,558	21.53	39	1,685,175	23.32	(5) ◆	(2) ◆	(3) ◆
Native Load Total	**$ 541**	**19,238,089**	**$ 28.13**	**$ 557**	**19,666,392**	**$ 28.38**	**$ (16)** ◆	**$ (11)** ◆	**$ (6)** ◆

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD			YTD		
	Act	Bud	Variance	Act	Bud	Variance
Commercial	15	18	(2)	91	100	(9)
Industrial	17	19	(2)	113	121	(8)
Municipals	5	5	(0)	28	31	(3)
Other	6	6	0	38	36	2
Native Load Total	**44**	**48**	**(4)**	**270**	**287**	**(18)**

Weather Statistics	MTD			YTD		
	Act	+/- Bud		Act	+/- Bud	
Heating Degree Days - Louisville	0	0	0%	2,734	130	5%
Heating Degree Days - Lexington	0	0	0%	2,892	55	2%
Cooling Degree Days - Louisville	345	(69)	-17%	828	(39)	-4%
Cooling Degree Days - Lexington	301	(46)	-13%	722	27	4%

Gas Gross Margin July 2013

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**$ -** 🟢	**$ 38**	**$ 35**		**$ 3** 🟢
Gas Supply Costs								
Gas Supply Costs	(4)	(3)	$ (1)		(98)	(92)	$ (6)	
GSC Revenue	4	3	1		98	93	5	
Net Gas Supply Costs				**-** 🟢				**(1)** 🔴
Retail Gas (a)	**3**	**2**		**1** 🟢	**56**	**52**		**4** 🟢
Wholesale Gas (a)	**-**	**-**		**-** 🟢	**-**	**-**		**-** 🟢
DSM	**0**	**(0)**		**0** 🟢	**0**	**(1)**		**1** 🟢
GLT	**0**	**0**		**-** 🟢	**2**	**2**		**(0)** 🔴
WNA	**-**	**-**		**-** 🟢	**(3)**	**-**		**(3)** 🔴
Other Margin	**(0)**	**0**		**(1)** 🔴	**1**	**2**		**(1)** 🔴
Gas Margin Variance				**$ 0** 🟢				**$ 2** 🟢

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 1	404,238	$ 2.87	$ 1	392,829	$ 2.68	$ 0 🟢	$ - 🟢	$ 0 🟢
Commercial	1	291,239	2.34	1	264,240	2.08	0 🟢	0 🟢	0 🟢
Industrial	0	97,974	1.63	0	43,228	1.86	0 🟢	0 🟢	- 🟢
Public Authority	0	29,436	2.88	0	36,921	1.87	- 🟢	- 🟢	- 🟢
Transportation	1	704,070	0.99	0	642,511	0.42	0 🟢	- 🟢	0 🟢
Ultimate Consumer	$ 3	1,526,957	$ 1.82	$ 2	1,379,729	$ 1.47	$ 1 🟢	$ 0 🟢	$ 1 🟢

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 35	13,088,550	$ 2.65	$ 34	13,150,852	$ 2.58	$ 1 🟢	$ (0) 🔴	$ 1 🟢
Commercial	12	5,686,227	2.05	12	5,705,871	2.05	- 🟢	- 🟢	- 🟢
Industrial	1	724,787	1.72	1	559,039	1.85	0 🟢	0 🟢	(0) 🔴
Public Authority	2	1,010,536	2.00	2	1,036,680	1.97	- 🟢	(0) 🔴	- 🟢
Transportation	6	7,150,094	0.83	3	6,831,003	0.44	3 🟢	0 🟢	3 🟢
Ultimate Consumer	$ 56	27,660,194	$ 2.01	$ 52	27,283,444	$ 1.90	$ 4 🟢	$ 0 🟢	$ 4 🟢

O&M July 2013

($ Millions)

	MTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 16	$ 17	$ 1	$ -	$ 1	$ (0)	$ 0	$ 0	$ -	$ 0
Project Engineering	0	0	0	-	$ 0	-	(0)	(0)	-	0
Transmission	2	3	1	-	$ (0)	-	1	(0)	-	0
Energy Supply and Analysis	1	1	0	-	$ 0	-	0	0	-	0
Electric Distribution	8	6	(2)	-	$ (1)	-	(2)	0	(0)	(0)
Gas Distribution	2	3	0	-	$ 0	-	0	(0)	(0)	0
Customer Services	6	8	2	-	$ 0	-	0	0	1	1
Chief Operations Officer	**36**	**38**	**2**	**-**	**1**	**(0)**	**(1)**	**0**	**1**	**1**
Information Technology	4	4	1	-	0	-	0	0	-	0
General Counsel	2	2	1	-	0	-	1	0	-	0
Human Resources	1	1	0	-	0	-	0	0	-	0
Supply Chain	0	0	0	-	0	-	(0)	(0)	-	0
Chief Administrative Officer	**6**	**8**	**2**	**-**	**1**	**-**	**1**	**0**	**-**	**0**
Chief Financial Officer	**2**	**2**	**0**	**-**	**0**	**-**	**(0)**	**0**	**-**	**(0)**
Corporate	**12**	**12**	**(0)**	**(0)**	**(0)**	**-**	**0**	**0**	**-**	**(0)**
O&M Total MTD	**$ 56**	**$ 59**	**$ 3**	**$ (0)**	**$ 1**	**$ (0)**	**$ 0**	**$ 0**	**$ 1**	**$ 1**

	YTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 127	$ 132	$ 5	$ -	$ 4	$ 6	$ 1	$ 0	$ -	$ (6)
Project Engineering	0	0	0	-	0	-	(0)	(0)	-	0
Transmission	17	18	1	-	(0)	-	1	0	-	(0)
Energy Supply and Analysis	5	6	1	-	0	-	0	0	-	1
Electric Distribution	42	40	(2)	-	(1)	-	(2)	1	(0)	1
Gas Distribution	18	19	1	-	0	-	1	(0)	(0)	0
Customer Services	45	52	8	-	2	-	1	0	4	0
Chief Operations Officer	**254**	**268**	**14**	**-**	**5**	**6**	**3**	**1**	**4**	**(4)**
Information Technology	28	28	1	-	1	-	(1)	(0)	-	1
General Counsel	16	18	2	-	0	-	2	0	-	(0)
Human Resources	3	4	1	-	0	-	0	0	-	0
Supply Chain	2	2	0	-	0	-	0	0	-	0
Chief Administrative Officer	**49**	**53**	**4**	**-**	**2**	**-**	**1**	**(0)**	**-**	**1**
Chief Financial Officer	**10**	**11**	**1**	**-**	**0**	**-**	**(0)**	**0**	**-**	**1**
Corporate	**88**	**85**	**(3)**	**(5)**	**(1)**	**-**	**2**	**1**	**0**	**(1)**
O&M Total YTD	**$ 401**	**$ 417**	**$ 16**	**$ (5)**	**$ 6**	**$ 6**	**$ 6**	**$ 2**	**$ 4**	**$ (4)**

	Full Year			Variances						
	Forecast	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 225	$ 227	$ 2	$ -	$ 3	$ 1	$ (0)	$ (3)	$ -	$ 1
Project Engineering	1	1	0	-	(0)	-	(0)	(0)	-	0
Transmission	28	29	1	-	(0)	-	2	(2)	-	1
Energy Supply and Analysis	9	10	1	-	0	-	0	0	-	0
Electric Distribution	70	69	(1)	-	(1)	-	1	1	-	(3)
Gas Distribution	33	34	1	-	(0)	-	1	0	-	(1)
Customer Services	84	91	7	-	2	-	1	(0)	3	1
Chief Operations Officer	**450**	**461**	**10**	**-**	**4**	**1**	**5**	**(3)**	**3**	**(0)**
Information Technology	49	50	2	-	2	-	(1)	-	-	1
General Counsel	31	34	4	-	0	-	2	-	-	1
Human Resources	7	7	0	-	0	-	0	(0)	-	(0)
Supply Chain	3	3	0	-	(0)	-	0	-	-	0
Chief Administrative Officer	**90**	**95**	**6**	**-**	**2**	**-**	**2**	**(0)**	**-**	**2**
Chief Financial Officer	**18**	**19**	**1**	**-**	**0**	**-**	**0**	**-**	**-**	**1**
Corporate	**142**	**146**	**4**	**(5)**	**(1)**	**-**	**1**	**(1)**	**0**	**8**
O&M Total Full Year	**$ 700**	**$ 721**	**$ 20**	**$ (5)**	**$ 6**	**$ 1**	**$ 8**	**$ (4)**	**$ 3**	**$ 11**

Financing Activities July 2013

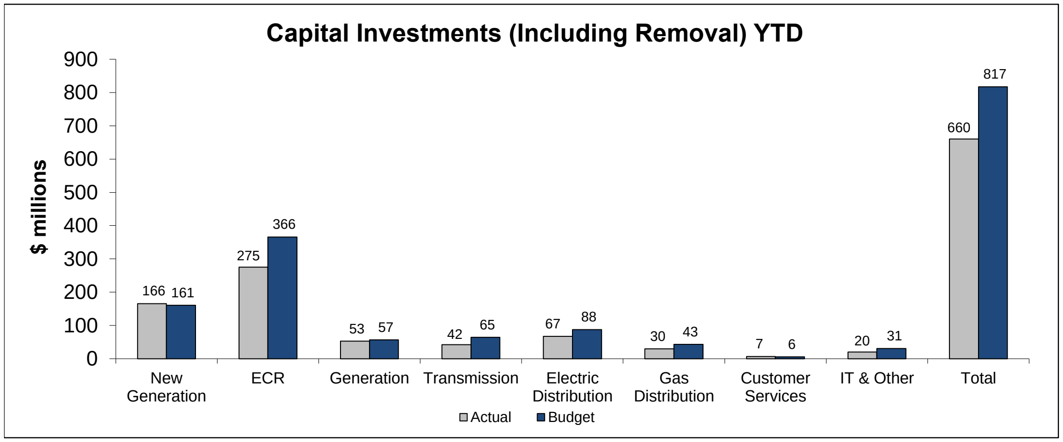
($ Millions)

	MTD			YTD			Full Year		
Balance Sheet	**Actual**	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**	**Forecast**	**Budget**	**Variance**
PCB									
Beg Bal	$ 931.8	$ 931.8	$ -	$ 932.0	$ 932.0	$ 0.0	$ 932.0	$ 932.0	$ -
End Bal	931.8	931.8	-	931.8	931.8	-	931.7	931.7	-
Ave Bal	**$ 931.8**	**$ 931.8**	**$ -**	**$ 931.9**	**$ 931.9**	**$ (0.0)**	**$ 931.8**	**$ 931.8**	**$ -**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 6.1**	**$ 8.0**	**$ 1.9**	**$ 12.0**	**$ 13.6**	**$ 1.6**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.11%**	**1.46%**	**0.34%**	**1.29%**	**1.46%**	**0.17%**
FMB/Sr Nts									
Beg Bal	$ 3,143.6	$ 3,143.6	$ (0.0)	$ 3,142.8	$ 3,142.8	$ 0.0	$ 3,142.8	$ 3,142.8	$ 0.0
End Bal	3,143.7	3,143.7	(0.0)	3,143.7	3,143.7	(0.0)	3,644.4	3,694.4	50.0
Ave Bal	**$ 3,143.7**	**$ 3,143.7**	**$ (0.0)**	**$ 3,143.3**	**$ 3,143.3**	**$ 0.1**	**$ 3,227.0**	**$ 3,235.3**	**$ 8.3**
Interest Exp	**$ 9.6**	**$ 9.6**	**$ (0.0)**	**$ 66.9**	**$ 66.9**	**$ (0.0)**	**$ 120.3**	**$ 120.2**	**$ (0.1)**
Rate	**0.00%**	**0.00%**	**0.00%**	**3.61%**	**3.61%**	**0.00%**	**3.73%**	**3.72%**	**-0.01%**
Short-term Debt									
Beg Bal	$ 324.8	$ 418.4	$ 93.6	$ 149.7	$ 149.7	$ (0.0)	$ 149.7	$ 149.7	$ (0.0)
End Bal	324.6	449.0	124.4	324.6	449.0	124.4	210.0	176.3	(33.7)
Ave Bal	**$ 324.7**	**$ 433.7**	**$ 109.0**	**$ 237.1**	**$ 330.3**	**$ 93.2**	**$ 329.2**	**$ 359.0**	**$ 29.8**
Interest Exp	**$ 0.2**	**$ 0.2**	**$ 0.0**	**$ 1,345.4**	**$ 1,294.0**	**$ (51.4)**	**$ 2.5**	**$ 1.2**	**$ (1.3)**
Rate	**0.00%**	**0.00%**	**0.00%**	**0.96%**	**0.67%**	**-0.30%**			
Total End Bal	**$ 4,400.1**	**$ 4,524.5**	**$ 124.4**	**$ 4,400.1**	**$ 4,524.5**	**$ 124.4**	**$ 4,786.1**	**$ 4,802.4**	**$ 16.3**
Total Average Bal	**$ 4,400.2**	**$ 4,509.2**	**$ 109.0**	**$ 4,312.3**	**$ 4,405.6**	**$ 93.3**	**$ 4,488.1**	**$ 4,526.2**	**$ 38.1**
Total Expense Excl I/C	**$ 12.3**	**$ 12.5**	**$ 0.2**	**$ 86.5**	**$ 87.4**	**$ 0.9**	**$ 153.5**	**$ 153.8**	**$ 0.4**
Rate	**3.60%**	**3.57%**	**-0.03%**	**3.41%**	**3.37%**	**-0.04%**	**3.42%**	**3.40%**	**-0.02%**

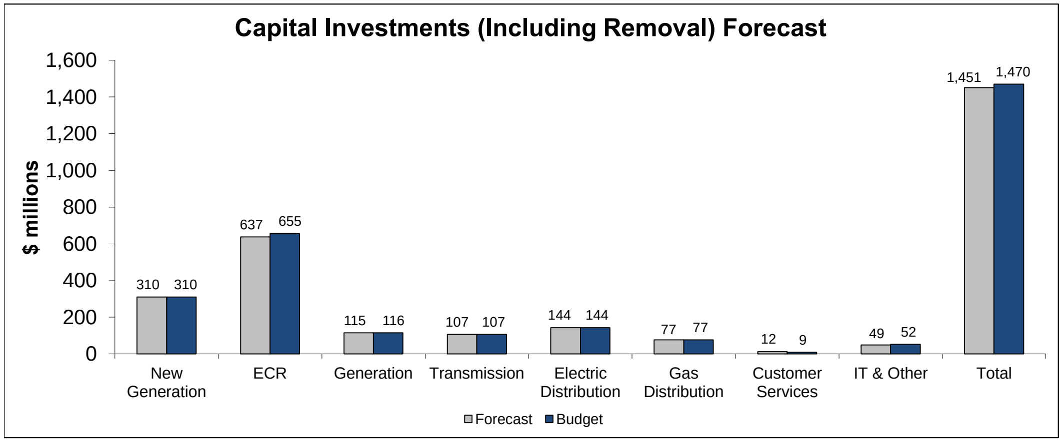
Balance Sheet July 2013

($ Millions)

	YTD	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 15	$ 10	$ 5	
Accounts Receivable (Trade)	376	329	47	Due primarily to tariff rate variance in receivable logic and extended due date granted in rate case.
Inventory	251	237	14	Increase in fuel ($7m), gas ($2m) and materials and supplies ($4m).
Deferred Income Taxes	11	13	(3)	
Prepayments and other current assets	133	69	64	Primarily due to short-term derivative asset gain from forward hedges entered into in November 2012 with PPL as counterparty as a result of an increase in market interest rates ($71m).
Total Current Assets	786	658	128	
Property, Plant, and Equipment	8,778	8,935	(157)	See capital chart for details.
Intangible Assets	241	241	(1)	
Other Property and Investments	1	1	1	
Regulatory Assets	599	640	(40)	Primarily interest rate swaps ($17m) and decrease in FAC ($25m).
Goodwill	997	997	-	
Other Long-term Assets	97	104	(7)	
Total Assets	**$ 11,499**	**$ 11,575**	**$ (76)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 303	$ 231	$ 72	Primarily differences in capex accrual and an increase in retainage fees and fuel volumes.
Accounts Payable - Affiliated Company	(0)	(0)	0	
Customer Deposits	49	48	1	
Derivative Liability	4	5	(1)	
Accrued Taxes	48	35	13	
Other Current Liabilities	131	122	9	
Total Current Liabilities	535	442	93	
Debt - Affiliated Company	-	-	-	
Debt	4,400	4,525	(124)	Less short-term debt issued than budgeted ($171m) due to lower capital spend, offset by notes payable to PPL ($47m). See Financing Activities page for more details.
Total Debt	4,400	4,525	(124)	
Deferred Tax Liabilities	637	668	(30)	Timing of recording of deferred taxes in actuals vs. budget.
Investment Tax Credit	136	135	1	
Accumulated Provision for Pension and Related Benefits	266	270	(4)	
Asset Retirement Obligation	127	129	(2)	
Regulatory Liabilities	1,060	995	65	Primarily due to short-term derivative asset gain from forward hedges entered into in November 2012 with PPL as counterparty as a result of an increase in market interest rates ($71m).
Derivative Liability	37	54	(16)	Increase in interest rate swaps with non-related third parties due to an increase in market interest rates causing a decrease in the derivative liability.
Other Liabilities	243	237	6	
Total Deferred Credits and Other Liabilities	2,507	2,487	19	
Equity	4,057	4,121	(64)	
Total Liabilities and Equity	**$ 11,499**	**$ 11,575**	**$ (76)**	



Capital was $157m lower than budget due mainly to slower than expected mobilization for Mill Creek ($37m) and Ghent ($24) environmental air work. Spending delays on Ghent and Brown landfill projects ($14m) and other environmental projects ($6m) are expected to reverse by year end with the remaining ($10m) due to delay in the Trimble County landfill to 2015. Transmission underspend ($23m) was mainly due to delayed spending on Cane Run 7, New Albany transmission work and line rating projects; Distribution variances ($34m) were driven by timing of circuit hardening, major substation projects, main replacement and gas riser projects.



Capital is projected to be $19m lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.

Performance Report

August 2013

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Kentucky Regulated Dashboard

August 2013

Operational Metrics	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.34	0.69	1.41	1.52	N/A	1.35
Employee lost-time incidents	0	0	0	4	N/A	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,207	3,459	23,133	24,077	34,774	35,128
Utility EFOR	4.8%	5.1%	7.6%	5.1%	N/A	5.1%
Utility EAF	92.4%	92.3%	81.8%	87.9%	N/A	87.08%
Combined SAIFI	0.10	0.13	0.71	0.90	N/A	1.22
Combined SAIDI (minutes)	8.51	10.72	64.72	83.02	N/A	109.60
GwH Sales						
Residential	1,015	1,138	7,403	7,589	10,904	10,912
Commercial	762	803	5,266	5,482	7,858	8,063
Industrial	886	915	6,519	6,640	9,949	9,891
Municipals	175	199	1,277	1,326	1,904	1,944
Other	254	275	1,866	1,961	2,791	2,901
Off-System Sales	23	3	306	324	380	465
Total	3,115	3,334	22,637	23,322	33,785	34,175
Weather-Normalized Sales Growth(1)			**W-N**			
Residential			0.90%			
Commercial			-1.41%			
Industrial			1.04%			
Other(2)			-1.68%			
Total			0.01%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE(3)	12.7%	13.1%	10.4%	10.4%	9.5%	9.6%
Electric Margins	$152	$162	$1,075	$1,109	$1,596	$1,638
Gas Margins	$7	$8	$103	$102	$157	$156
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$32	$31	$197	$193	$321	$310
ECR	39	57	314	423	610	655
Generation	10	10	64	66	135	117
Transmission	7	9	49	74	100	107
Electric Distribution	13	14	80	102	149	144
Gas Distribution	8	9	38	53	76	77
Customer Services	1	1	8	7	13	9
IT and Other	3	5	23	35	47	51
Total	$113	$136	$773	$953	$1,451	$1,470
O&M ($ millions)(4)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$35	$40	$288	$308	$447	$461
Administrative	$7	8	$56	$61	90	95
Finance and Accounting	$2	2	$12	$13	18	19
Corp Burdens & Other Charges	$11	12	$99	$97	145	146
Total	$54	$62	$455	$479	$700	$721
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,363	3,431	3,363	3,431	3,429	3,435
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	3	4	7	9	N/A	14
NERC Possible Violations(5)	2	13	9	21	N/A	29

Variance Explanations

- The generation fleet's EAF and EFOR are unfavorable to budget due primarily to Ghent Unit 4 cooling tower header failure, Trimble County Unit 2 low pressure turbine bearing failure and Cane Run Unit 4 generator rotor winding shorts.
- Lower margins in August due primarily to $9 million of lower energy revenues, as volumes were down 7% due to unseasonably mild temperatures, and $6 million of lower demand charge revenues, partially offset by favorable margins of $3 million on retail rate mechanisms.
- Lower margins YTD due primarily to $26 million of lower energy revenues, as volumes were down 3% due to mild weather, and $23 million of lower demand charge revenues, partially offset by favorable margins of $14 million on retail rate mechanisms.
- Capital was $23 million lower than budget in August due mainly to revised schedules for Mill Creek environmental work of $10 million and delay in Trimble County landfill to 2015 of $6 million. Timing of distribution capital spend driven partly by priority pipeline and gas riser replacements are not expected to cause full-year distribution variances.
- Capital was $180 million lower than budget YTD due mainly to slower than expected mobilization for Mill Creek of $47 million and Ghent environmental air work of $23 million. Spending delays on Brown landfill of $20 million and the delay of Trimble County landfill to 2015 due to permitting issues of $16 million are remaining environmental variances. Transmission underspend of $25 million was due mainly to delayed spending on Cane Run U7, New Albany transmission work and line rating projects; Distribution variances of $37 million were driven by timing of circuit hardening, major substation projects, main replacement and gas riser projects and are expected to reverse by year end.
- Full year capital is projected to be $19 million lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.
- Lower O&M in August due primarily to $3 million of lower outside services and $2 million of lower materials and other nonlabor costs.
- Lower O&M YTD due primarily to $8 million of labor savings, $7 million of lower outside services, $4 million of lower uncollectible accounts and $3 million of lower material costs.

Major Developments

- On September 6, 2013, LG&E and PPL received Notice of Intent to Sue for alleged violations of the federal Resource Conservation and Recovery Act and the Clean Air Act associated with LG&E's operation of the Cane Run generating facility. The suit itself is expected to be filed shortly before the end of the year. The notice does not indicate the court in which the action may be filed. We believe this private litigation may be a precursor to further civil litigation against the company from residents in and around the Cane Run site. LG&E is closing the Cane Run coal facility and landfill in mid-2015. LKE and PPL legal teams are jointly working to identify and hire legal counsel to assist in the defense of this suit and to prepare for potential additional litigation.
- LG&E and KU has received two awards for its safety and community initiatives.
  - o LG&E and KU won the National Highway Traffic Safety Administration 2013 Outstanding Service Award for its efforts to combat distracted driving.
  - o The Business First newspaper announced that LG&E and KU has earned a "Partners in Philanthropy Award" for being an outstanding corporate citizen. LG&E and KU achieved a third-place finish in the large-company category of firms with revenues higher than $50 million. This marks the second consecutive year LG&E and KU has received a strong ranking in the category, having finished fourth in last year's competition.

Significant Future Events

- LG&E and KU completed their evaluation of alternatives for generation capacity. LG&E and KU expect to make a filing with the Kentucky Public Service Commission in Q4 for a certificate of public convenience and necessity to build a new combined cycle gas unit for commercial operation in 2018.
- KU is proceeding with efforts to improve its returns on equity for its Old Dominion Power operations in Virginia and with the Kentucky municipal customers supplied under FERC-approved rates. KU is preparing rebuttal testimony and preparing for an October 1 hearing in the VA rate case and preparing to file a rate case at FERC during September.

(1) Percentages represent a trailing twelve months.

(2) "Other" is typically comprised of the public authority customer class and KU's 12 full-requirements wholesale municipal customers.

(3) Excludes goodwill and other purchase accounting adjustments.

(4) Net of cost recovery mechanisms.

(5) The nine NERC Possible Violation Issues for YTD Actual are expected to be resolved through NERC's Find, Fix and Track ("FFT") process without financial penalty.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget and Forecast (Month) August 2013

($ Millions)

	MTD				MTD			
	Actual	Budget	Variance	Comments	Actual	Q2 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 248	$ 275	$ (27)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.	$ 248	$ 267	$ (19)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.
Gas Revenues	11	12	(1)		11	12	(1)	
Total Revenues	259	287	(28)		259	279	(20)	
Cost of Sales:								
Fuel Electric Costs	83	95	12	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.	83	95	12	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.
Gas Supply Expenses	3	4	0		3	4	0	
Purchased Power	4	7	2		4	7	2	
Other Electric Cost	9	12	3		9	9	0	
Total Cost of Sales	100	117	18		100	115	15	
Gross Margin:								
Electric Margin	152	162	(10)	Primarily $9m of lower energy volumes (-7%) due to unseasonably mild weather, and $6m of lower demand charge revenues, partially offset by favorable margins of $3m on retail rate mechanisms.	152	156	(5)	Lower electric energy volumes due to unseasonably mild weather and economic conditions.
Gas Margin	7	8	(1)		8	8	(0)	
Total Gross Margin	159	170	(11)		159	164	(5)	
Operating Expenses:								
O&M	54	62	8	Primarily $3m of lower outside services and $2m of lower materials and other nonlabor costs.	54	60	7	Primarily $3m of lower outside services and $2m of lower materials and other nonlabor costs.
Depreciation & Amortization	27	28	1		27	27	0	
Taxes, Other than Income	4	4	(0)		4	4	0	
Total Operating Expenses	85	94	9		85	92	7	
Equity in earnings	-	(0)	0		-	0	(0)	
Other income	(1)	(0)	(0)		(1)	(0)	(0)	
EBIT	73	76	(3)		73	72	1	
Interest Expense	12	13	0		12	13	0	
Income from Ongoing Operations before income taxes	61	63	(2)		61	59	1	
Income Tax Expense	22	24	1		22	23	0	
Net Income (loss) from ongoing operations	**38**	**39**	**(1)**		**38**	**37**	**2**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	(0)	(0)	0		(0)	0	(0)	
Net Income (loss)	$ 38	$ 39	$ (1)		$ 38	$ 37	$ 1	
KY Regulated Financing Costs	(3)	(2)	(0)		(3)	(3)	0	
KY Regulated Net Income	$ 36	$ 37	$ (1)		$ 36	$ 34	$ 2	
Earnings Per Share	$ 0.05	$ 0.06	$ (0.01)		$ 0.05	$ 0.05	$ 0.01	

Income Statement: Actual vs. Budget (YTD) August 2013

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,798	$ 1,868	$ (70)	Primarily lower electric energy volumes driven by unseasonably mild weather and economic conditions and lower electric demand charge revenues.
Gas Revenues	204	203	1	
Total Revenues	2,002	2,071	(69)	
Cost of Sales:				
Fuel Electric Costs	617	639	21	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.
Gas Supply Expenses	101	101	0	
Purchased Power	39	45	6	
Other Electric Cost	66	75	9	Lower electric volumes and ECR costs.
Total Cost of Sales	823	859	36	
Gross Margin:				
Electric Margin	1,075	1,109	(34)	Primarily $26m of lower energy volumes (-3%) due to unseasonably mild weather, and $23m of lower demand charge revenues, partially offset by favorable margins of $14m on retail rate mechanisms.
Gas Margin	103	102	1	
Total Gross Margin	1,178	1,211	(33)	
Operating Expenses:				
O&M	455	479	24	Primarily $8m of labor savings, $7m of lower outside services, $4m of lower uncollectible accounts and $3m of lower material costs.
Depreciation & Amortization	218	224	6	
Taxes, Other than Income	32	32	0	
Total Operating Expenses	705	735	30	
Equity in earnings	-	(1)	1	
Other income	(6)	(6)	0	
EBIT	467	470	(2)	
Interest Expense	99	100	1	
Income from Ongoing Operations before income taxes	368	370	(1)	
Income Tax Expense	137	138	1	
Net Income (loss) from ongoing operations	**231**	**231**	**(0)**	
Non Operating Income	0	-	0	
Discontinued Operations	2	(1)	3	
Net Income (loss)	$ 233	230	$ 3	
KY Regulated Financing Costs	(31)	(27)	(3)	
KY Regulated Net Income	$ 201	$ 202	$ (1)	
Earnings Per Share	$ 0.33	$ 0.33	$ (0.00)	

Income Statement: Forecast vs. Budget and Prior Forecast — August 2013

($ Millions)

	Full Year				Full Year			
	Forecast	Budget	Variance	Comments	Forecast	Q2 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 2,664	$ 2,753	$ (88)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.	$ 2,664	$ 2,706	$ (42)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.
Gas Revenues	313	313	1		313	315	(2)	
Total Revenues	2,977	3,065	(88)		2,977	3,021	(44)	
Cost of Sales:								
Fuel Electric Costs	905	928	23	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.	905	928	23	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.
Gas Supply Expenses	156	157	1		156	158	2	
Purchased Power	57	67	10	Lower purchases than originally planned and updated to more accurately reflect trend in actuals.	57	66	9	Lower purchases than originally planned and updated to more accurately reflect trend in actuals.
Other Electric Cost	106	119	13	Lower electric volumes.	106	103	(3)	
Total Cost of Sales	1,224	1,271	47		1,224	1,255	31	
Gross Margin:								
Electric Margin	1,596	1,638	(42)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.	1,596	1,609	(13)	Lower electric energy volumes due to unseasonably mild weather in July and August and economic conditions.
Gas Margin	157	156	1		157	157	-	
Total Gross Margin	1,753	1,794	(41)		1,753	1,766	(13)	
Operating Expenses:								
O&M	700	721	22	Favorable labor and burdens ($7m), uncollectible accounts ($4m), outside services ($5m) and materials ($5m).	700	704	5	
Depreciation & Amortization	329	338	9	Revised estimates based on delayed capital spend in 2012 and revised in-service dates for capital projects in 2013.	329	329	-	
Taxes, Other than Income	48	48	(0)		48	48	-	
Total Operating Expenses	1,077	1,107	30		1,077	1,082	5	
Equity in earnings	0	(1)	1		0	0	-	
Other income	(8)	(8)	1		(8)	(7)	(1)	
EBIT	668	677	(10)		668	677	(10)	
Interest Expense	153	154	0		153	153	(0)	
Income from Ongoing Operations before income taxes	514	524	(10)		514	524	(10)	
Income Tax Expense	191	196	5		191	196	5	
Net Income (loss) from ongoing operations	**323**	**328**	**(4)**		**323**	**328**	**(4)**	
Non Operating Income	0	-	0		0	1	(0)	
Discontinued Operations	0	(1)	2		0	1	(1)	
Net Income (loss)	$ 324	$ 326	$ (3)		$ 324	$ 329	$ (6)	
KY Regulated Financing Costs	(41)	(37)	(4)		(41)	(40)	(1)	
KY Regulated Net Income	$ 283	$ 289	$ (7)		$ 283	$ 289	$ (6)	
Earnings Per Share	$ 0.45	$ 0.46	$ (0.01)		$ 0.45	$ 0.46	$ (0.01)	

Electric Gross Margin

August 2013

($ Millions)

	MTD						YTD					
	Actual	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**	**Actual**	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**
Base Electric Margin:						**$ (15)** ◆						**$ (48)** ◆
Energy Volumes (a)	3,092,030	3,331,056	(239,026)	$ -	$ (8)		22,330,119	22,997,448	(667,329)	$ -	$ (20)	
Energy Prices (a)					(1)						(6)	
Customer Charges (Avg. Customers)	935,516	946,734	(11,218)		(0)		935,322	944,907	(9,584)		1	
Demand Charges (b)					(6)						(23)	
ECR:						**(0)** ◆						**(2)** ◆
Average Rate Base	$ 768	$ 886	$ (119)	10.43%	$ (0.9)		$ 628	$ 718	$ (90)	10.44%	$ (5.6)	
Cost of Capital	10.27%	10.43%	-0.16%	$ 768	(0.1)		10.30%	10.44%	-0.14%	$ 628	(0.5)	
Jurisdictional Factor	89.85%	89.98%	-0.13%	$ 768	-		88.79%	88.78%	0.01%	$ 628	-	
Other					0.9						4.3	
DSM:						**1** ●						**4** ●
Program Expense (Revenue Net of Expense)	$ 0.1	$ -			$ 0.1		$ 0.5	$ 0.3			$ 0.2	
Lost Sales	1.9	1.0			0.9		11.0	8.1			2.9	
Incentive	0.1	0.1			-		0.8	0.5			0.3	
Balancing Adjustment	0.2	-			0.2		0.7	-			0.7	
Net Fuel Recovery	$ 1.0	$ (0.9)				**2** ●	$ 2	$ (5)				**6** ●
Purchase Power Demand	(2.3)	(2.6)				**0** ●	(19.0)	(20.2)				**1** ●
Transmission	1.4	0.8				**1** ●	8.9	6.8				**2** ●
Other	(1.0)	(2.2)				**1** ●	(13.0)	(14.8)				**2** ●
Retail Margin Variance						**(10)** ◆						**(35)** ◆
Off-System Margin Variance						**0** ●						**1** ●
Electric Margin Variance						**$ (10)** ◆						**$ (34)** ◆

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 50	1,015,005	$ 49.03	$ 56	1,138,063	$ 48.96	$ (6) ◆	$ (6) ◆	$ 0 ●
Commercial	24	761,805	30.91	26	803,441	32.36	(3) ◆	(1) ◆	(1) ◆
Industrial	8	886,054	8.97	8	915,465	8.96	(0) ◆	(0) ◆	- ●
Municipals	1	175,459	5.56	1	198,837	4.69	0 ●	(0) ◆	0 ●
Other	6	253,707	23.21	6	275,250	22.74	(0) ◆	(1) ◆	0 ●
Native Load Total	**$ 88**	**3,092,030**	**$ 28.50**	**$ 97**	**3,331,056**	**$ 29.15**	**$ (9)** ◆	**$ (8)** ◆	**$ (1)** ◆

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 360	7,401,682	$ 48.59	$ 368	7,589,006	$ 48.47	$ (8) ◆	$ (9) ◆	$ 1 ●
Commercial	166	5,265,999	31.52	176	5,481,708	32.13	(10) ◆	(7) ◆	(3) ◆
Industrial	57	6,519,085	8.69	59	6,640,327	8.85	(2) ◆	(1) ◆	(1) ◆
Municipals	6	1,277,087	4.92	6	1,325,983	4.69	0 ●	(0) ◆	0 ●
Other	41	1,866,265	21.76	46	1,960,425	23.24	(5) ◆	(2) ◆	(3) ◆
Native Load Total	**$ 629**	**22,330,119**	**$ 28.18**	**$ 655**	**22,997,448**	**$ 28.46**	**$ (25)** ◆	**$ (20)** ◆	**$ (6)** ◆

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD			YTD		
	Act	**Bud**	**Variance**	**Act**	**Bud**	**Variance**
Commercial	15	18	(3)	106	118	(11)
Industrial	17	20	(3)	130	141	(11)
Municipals	5	5	(1)	32	36	(4)
Other	6	6	-	44	42	2
Native Load Total	**43**	**49**	**(6)**	**313**	**336**	**(23)**

Weather Statistics	MTD			YTD		
	Act	**+/- Bud**		**Act**	**+/- Bud**	
Heating Degree Days - Louisville	0	0	0%	2,734	130	5%
Heating Degree Days - Lexington	3	1	50%	2,895	56	2%
Cooling Degree Days - Louisville	375	(16)	-4%	1,203	(55)	-4%
Cooling Degree Days - Lexington	315	(10)	-3%	1,037	17	2%

Gas Gross Margin — August 2013

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**$ -** 🟢	**$ 43**	**$ 40**		**$ 2** 🟢
Gas Supply Costs								
Gas Supply Costs	(4)	(3)	$ (1)		(102)	(95)	$ (7)	
GSC Revenue	3	3	0		101	96	4	
Net Gas Supply Costs				**(1)** ♦				**(2)** ♦
Retail Gas (a)	**2**	**2**		**-** 🟢	**58**	**54**		**4** 🟢
Wholesale Gas (a)	**-**	**-**		**-** 🟢	**-**	**-**		**-** 🟢
DSM	**-**	**(0)**		**0** 🟢	**0**	**(1)**		**1** 🟢
GLT	**0**	**0**		**-** 🟢	**2**	**2**		**(0)** ♦
WNA	**-**	**-**		**-** 🟢	**(3)**	**-**		**(3)** ♦
Other Margin	**0**	**0**		**(0)** ♦	**1**	**2**		**(1)** ♦
Gas Margin Variance				**$ (1)** ♦				**$ 1** 🟢

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 1	356,992	$ 2.38	$ 1	399,022	$ 2.68	$ (0) ♦	$ (0) ♦	$ (0) ♦
Commercial	0	265,909	1.60	1	259,461	2.08	(0) ♦	- 🟢	(0) ♦
Industrial	0	73,215	1.52	0	48,848	1.88	- 🟢	- 🟢	- 🟢
Public Authority	-	33,240	0.65	0	49,902	1.92	(0) ♦	- 🟢	- 🟢
Transportation	1	745,479	0.96	0	648,787	0.41	0 🟢	- 🟢	0 🟢
Ultimate Consumer	$ 2	1,474,835	$ 1.44	$ 2	1,406,020	$ 1.47	$ - 🟢	$ - 🟢	$ 0 🟢

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 36	13,445,542	$ 2.64	$ 35	13,549,874	$ 2.59	$ 0 🟢	$ (0) ♦	$ 1 🟢
Commercial	12	5,949,293	2.03	12	5,965,332	2.05	(0) ♦	- 🟢	(0) ♦
Industrial	1	798,002	1.70	1	607,886	1.85	0 🟢	0 🟢	(0) ♦
Public Authority	2	1,043,776	1.96	2	1,086,582	1.96	(0) ♦	(0) ♦	- 🟢
Transportation	7	7,895,573	0.84	3	7,479,789	0.44	3 🟢	0 🟢	3 🟢
Ultimate Consumer	$ 58	29,132,186	$ 1.98	$ 54	28,689,464	$ 1.88	$ 4 🟢	$ 0 🟢	$ 4 🟢

O&M	**August 2013**

($ Millions)

	MTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 16	$ 18	$ 2	$ -	$ 1	$ (0)	$ 1	$ 0	$ -	$ 0
Project Engineering	0	0	0	-	$ 0	-	(0)	(0)	-	0
Transmission	2	3	0	-	$ (0)	-	(0)	(0)	-	0
Energy Supply and Analysis	1	1	0	-	$ (0)	-	0	0	(0)	0
Electric Distribution	6	7	1	-	$ (0)	-	0	1	(0)	0
Gas Distribution	2	3	1	-	$ 0	-	1	0	(0)	0
Customer Services	8	8	1	-	$ 0	-	0	0	0	0
Chief Operations Officer	**35**	**40**	**5**	**-**	**1**	**(0)**	**2**	**1**	**0**	**1**
Information Technology	4	4	0	-	0	-	0	0	-	(0)
General Counsel	2	3	1	-	(0)	-	1	0	-	0
Human Resources	1	1	0	-	(0)	-	(0)	0	-	0
Supply Chain	0	0	0	-	0	-	0	0	-	0
Chief Administrative Officer	**7**	**8**	**1**	**-**	**0**	**-**	**1**	**0**	**-**	**0**
Chief Financial Officer	**2**	**2**	**0**	**-**	**0**	**-**	**(0)**	**0**	**-**	**0**
Corporate	**11**	**12**	**1**	**1**	**1**	**-**	**0**	**0**	**-**	**(0)**
O&M Total MTD	**$ 54**	**$ 62**	**$ 8**	**$ 1**	**$ 2**	**$ (0)**	**$ 3**	**$ 1**	**$ 0**	**$ 1**

	YTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 143	$ 150	$ 7	$ -	$ 4	$ 8	$ 2	$ 1	$ -	$ (8)
Project Engineering	0	1	0	-	0	-	(0)	(0)	-	0
Transmission	20	21	1	-	(0)	-	1	0	-	(0)
Energy Supply and Analysis	6	7	1	-	0	-	0	0	(0)	1
Electric Distribution	47	47	(0)	-	(1)	-	(2)	2	(0)	1
Gas Distribution	20	22	2	-	0	-	2	(0)	(0)	0
Customer Services	53	61	8	-	2	-	2	0	4	0
Chief Operations Officer	**288**	**308**	**20**	**-**	**6**	**8**	**5**	**2**	**4**	**(5)**
Information Technology	32	33	1	-	1	-	(1)	(0)	-	1
General Counsel	18	21	3	-	0	-	3	0	-	0
Human Resources	4	5	1	-	0	-	0	0	-	0
Supply Chain	2	2	0	-	0	-	0	0	-	0
Chief Administrative Officer	**56**	**61**	**5**	**-**	**2**	**-**	**2**	**0**	**-**	**1**
Chief Financial Officer	**12**	**13**	**1**	**-**	**0**	**-**	**(0)**	**0**	**-**	**1**
Corporate	**99**	**97**	**(2)**	**(4)**	**(0)**	**-**	**2**	**1**	**0**	**(1)**
O&M Total YTD	**$ 455**	**$ 479**	**$ 24**	**$ (4)**	**$ 8**	**$ 8**	**$ 9**	**$ 3**	**$ 4**	**$ (5)**

	Full Year			Variances						
	Forecast	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 223	$ 227	$ 4	$ -	$ 4	$ 3	$ 1	$ (3)	$ -	$ (0)
Project Engineering	1	1	0	-	(0)	-	(0)	(0)	-	0
Transmission	29	29	(0)	-	(0)	-	2	(2)	-	(0)
Energy Supply and Analysis	9	10	1	-	0	-	0	0	-	0
Electric Distribution	70	69	(1)	-	(1)	-	0	(0)	-	(0)
Gas Distribution	31	34	3	-	0	-	2	1	-	(0)
Customer Services	84	91	7	-	2	-	2	(0)	4	(1)
Chief Operations Officer	**447**	**461**	**14**	**-**	**6**	**3**	**7**	**(5)**	**4**	**(1)**
Information Technology	49	50	1	-	2	-	(1)	(0)	-	0
General Counsel	30	34	4	-	0	-	3	(0)	-	0
Human Resources	7	7	0	-	0	-	0	(0)	-	(0)
Supply Chain	3	3	0	-	0	-	0	-	-	0
Chief Administrative Officer	**90**	**95**	**6**	**-**	**2**	**-**	**3**	**(0)**	**-**	**0**
Chief Financial Officer	**18**	**19**	**1**	**-**	**0**	**-**	**0**	**-**	**-**	**1**
Corporate	**145**	**146**	**1**	**(5)**	**(0)**	**-**	**2**	**(0)**	**0**	**5**
O&M Total Full Year	**$ 700**	**$ 721**	**$ 22**	**$ (5)**	**$ 8**	**$ 3**	**$ 12**	**$ (5)**	**$ 4**	**$ 5**

Financing Activities August 2013

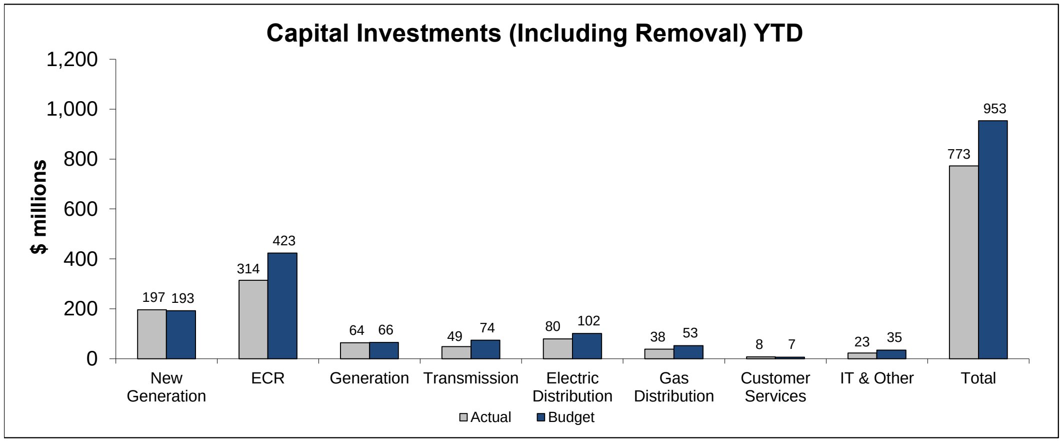
($ Millions)

	MTD			YTD			Full Year		
Balance Sheet	**Actual**	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**	**Forecast**	**Budget**	**Variance**
PCB									
Beg Bal	$ 931.8	$ 931.8	$ -	$ 932.0	$ 932.0	$ 0.0	$ 932.0	$ 932.0	$ -
End Bal	931.8	931.8	-	931.8	931.8	-	931.7	931.7	-
Ave Bal	**$ 931.8**	**$ 931.8**	**$ -**	**$ 931.9**	**$ 931.9**	**$ (0.0)**	**$ 931.8**	**$ 931.8**	**$ -**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 7.0**	**$ 9.1**	**$ 2.2**	**$ 12.0**	**$ 13.6**	**$ 1.6**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.11%**	**1.45%**	**0.34%**	**1.29%**	**1.46%**	**0.17%**
FMB/Sr Nts									
Beg Bal	$ 3,143.7	$ 3,143.7	$ (0.0)	$ 3,142.8	$ 3,142.8	$ 0.0	$ 3,142.8	$ 3,142.8	$ 0.0
End Bal	3,143.9	3,143.9	(0.0)	3,143.9	3,143.9	(0.0)	3,644.4	3,694.4	50.0
Ave Bal	**$ 3,143.8**	**$ 3,143.8**	**$ (0.0)**	**$ 3,143.3**	**$ 3,143.4**	**$ 0.1**	**$ 3,227.0**	**$ 3,235.3**	**$ 8.3**
Interest Exp	**$ 9.6**	**$ 9.6**	**$ (0.0)**	**$ 76.4**	**$ 76.4**	**$ (0.0)**	**$ 120.3**	**$ 120.2**	**$ (0.1)**
Rate	**0.00%**	**0.00%**	**0.00%**	**3.60%**	**3.60%**	**0.00%**	**3.73%**	**3.72%**	**-0.01%**
Short-term Debt									
Beg Bal	$ 324.6	$ 449.0	$ 124.4	$ 149.7	$ 149.7	$ (0.0)	$ 149.7	$ 149.7	$ (0.0)
End Bal	279.5	509.1	229.6	279.5	509.1	229.6	210.0	176.3	(33.7)
Ave Bal	**$ 302.0**	**$ 479.0**	**$ 177.0**	**$ 214.6**	**$ 352.7**	**$ 138.1**	**$ 329.2**	**$ 359.0**	**$ 29.8**
Interest Exp	**$ 0.2**	**$ 0.2**	**$ 0.0**	**$ 1,533.2**	**$ 1,525.3**	**$ (7.9)**	**$ 2.5**	**$ 1.2**	**$ (1.3)**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.06%**	**0.64%**	**-0.42%**			
Total End Bal	**$ 4,355.2**	**$ 4,584.7**	**$ 229.6**	**$ 4,355.2**	**$ 4,584.7**	**$ 229.6**	**$ 4,786.1**	**$ 4,802.4**	**$ 16.3**
Total Average Bal	**$ 4,377.7**	**$ 4,554.6**	**$ 177.0**	**$ 4,289.8**	**$ 4,428.0**	**$ 138.1**	**$ 4,488.1**	**$ 4,526.2**	**$ 38.1**
Total Expense Excl I/C	**$ 12.4**	**$ 12.5**	**$ 0.1**	**$ 98.9**	**$ 100.0**	**$ 1.1**	**$ 153.5**	**$ 153.8**	**$ 0.4**
Rate	**3.64%**	**3.54%**	**-0.10%**	**3.42%**	**3.35%**	**-0.07%**	**3.42%**	**3.40%**	**-0.02%**

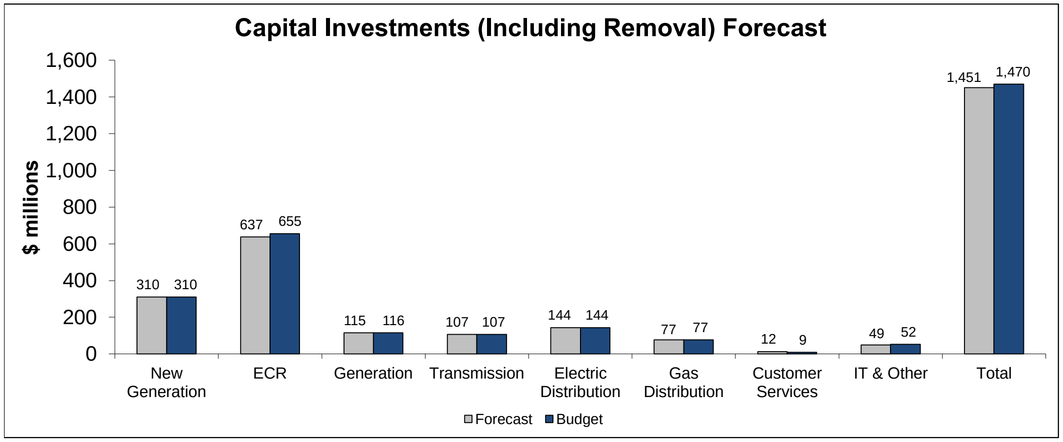
Balance Sheet August 2013

($ Millions)

	YTD	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 13	$ 11	$ 3	
Accounts Receivable (Trade)	373	334	39	Due primarily to tariff rate variance in receivable logic and extended due date granted in rate case.
Inventory	259	243	16	Primarily an increase in fuel ($10m) and materials and supplies ($4m).
Deferred Income Taxes	8	13	(6)	
Prepayments and other current assets	136	67	69	Primarily due to short-term derivative asset gain from forward hedges entered into in November 2012 with PPL as counterparty as a result of an increase in market interest rates ($78m).
Total Current Assets	789	669	121	
Property, Plant, and Equipment	8,859	9,043	(184)	See capital chart for details.
Intangible Assets	236	237	(1)	
Other Property and Investments	1	1	1	
Regulatory Assets	594	638	(45)	Primarily interest rate swaps ($20m) and decrease in FAC ($31m).
Goodwill	997	997	-	
Other Long-term Assets	96	103	(8)	
Total Assets	**$ 11,572**	**$ 11,688**	**$ (116)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 338	$ 206	$ 132	Primarily differences in capex accrual and an increase in retainage fees and fuel volumes.
Accounts Payable - Affiliated Company	47	(0)	47	Dividends declared.
Customer Deposits	49	48	1	
Derivative Liability	4	5	(1)	
Accrued Taxes	66	50	16	Timing of tax payments and accruals in actuals vs. budget.
Other Current Liabilities	145	134	11	
Total Current Liabilities	649	443	206	
Debt - Affiliated Company	-	-	-	
Debt	4,355	4,585	(230)	Less short-term debt issued than budgeted ($274m) due to lower capital spend, partially offset by notes payable to PPL ($45m). See Financing Activities page for more details.
Total Debt	4,355	4,585	(230)	
Deferred Tax Liabilities	642	681	(39)	Timing of recording of deferred taxes in actuals vs. budget.
Investment Tax Credit	136	135	1	
Accumulated Provision for Pension and Related Benefits	266	271	(4)	
Asset Retirement Obligation	126	129	(3)	
Regulatory Liabilities	1,067	993	74	Primarily due to short-term derivative asset gain from forward hedges entered into in November 2012 with PPL as counterparty as a result of an increase in market interest rates ($78m).
Derivative Liability	35	54	(18)	Increase in interest rate swaps with non-related third parties due to an increase in market interest rates causing a decrease in the derivative liability.
Other Liabilities	247	237	10	
Total Deferred Credits and Other Liabilities	2,520	2,500	19	
Equity	4,048	4,160	(112)	
Total Liabilities and Equity	**$ 11,572**	**$ 11,688**	**$ (116)**	



Capital was $180 million lower than budget YTD due mainly to slower than expected mobilization for Mill Creek of $47 million and Ghent environmental air work of $23 million. Spending delays on Brown landfill of $20 million and the delay of Trimble County landfill to 2015 due to permitting issues of $16 million are remaining environmental variances. Transmission underspend of $25 million was due mainly to delayed spending on Cane Run U7, New Albany transmission work and line rating projects; Distribution variances of $37 million were driven by timing of circuit hardening, major substation projects, main replacement and gas riser projects and are expected to reverse by year end.



Capital is projected to be $19m lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.

Performance Report

September 2013

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Kentucky Regulated Dashboard

September 2013

Operational Metrics	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.39	1.28	1.30	1.50	N/A	1.35
Employee lost-time incidents	0	0	1	4	N/A	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,739	2,802	25,871	26,879	34,120	35,128
Utility EFOR	6.3%	5.1%	7.5%	5.1%	N/A	5.1%
Utility EAF	88.0%	90.9%	82.4%	88.2%	N/A	87.08%
Combined SAIFI	0.08	0.09	0.80	0.98	N/A	1.22
Combined SAIDI (minutes)	6.65	8.31	71.37	91.33	N/A	109.60
Steam Fleet Commercial Availability	94.0%	N/A	91.9%	91.3%	N/A	N/A
GwH Sales						
Residential	774	884	8,177	8,473	10,595	10,912
Commercial	656	673	5,922	6,155	7,792	8,063
Industrial	798	792	7,317	7,432	9,786	9,891
Municipals	153	153	1,430	1,479	1,878	1,944
Other	258	239	2,124	2,200	2,805	2,901
Off-System Sales	14	22	320	346	494	465
Total	2,652	2,764	25,290	26,085	33,349	34,175
Weather-Normalized Sales Growth(1)			**W-N**			
Residential			1.42%			
Commercial			-1.41%			
Industrial			-0.02%			
Other(2)			-1.62%			
Total			-0.12%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE(3)	10.5%	9.3%	10.4%	10.2%	9.6%	9.6%
Electric Margins	$131	$143	$1,206	$1,252	$1,590	$1,638
Gas Margins	$8	$8	$112	$111	$157	$156
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$32	$31	$197	$193	$321	$310
ECR	36	52	350	474	610	655
Generation	14	10	110	107	135	117
Transmission	9	9	58	83	100	107
Electric Distribution	14	13	93	115	149	144
Gas Distribution	7	8	45	60	76	77
Customer Services	1	1	9	7	13	9
IT and Other	2	4	24	40	47	51
Total	$115	$128	$886	$1,079	$1,451	$1,470
O&M ($ millions)(4)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$34	$40	$323	$348	$442	$461
Administrative	$7	9	$64	$71	88	95
Finance and Accounting	$1	2	$13	$14	18	19
Corp Burdens & Other Charges	$10	12	$109	$109	146	146
Total	$53	$63	$508	$542	$693	$721
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,372	3,434	3,372	3,434	3,429	3,435
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	2	1	9	10	N/A	14
NERC Possible Violations(5)	0	3	9	24	N/A	29

Variance Explanations

- The generation fleet's EAF and EFOR are unfavorable to budget due primarily to Ghent Unit 4 cooling tower header failure, Trimble County Unit 2 low pressure turbine bearing failure and Cane Run Unit 4 generator rotor winding shorts.
- Lower margins in September due primarily to $6 million of lower energy revenues, as volumes were down 4% due to mild weather, and $5 million of lower demand charge revenues.
- Lower margins YTD due primarily to $32 million of lower energy revenues, as volumes were down 3% due to unseasonably mild temperatures, and $29 million of lower demand charge revenues, partially offset by favorable margins of $13 million on retail rate mechanisms.
- Capital was $193 million lower than budget YTD due mainly to slower than expected mobilization for Mill Creek of $55 million and Ghent environmental air work of $21 million. Spending delays on Brown landfill of $24m and the delay of Trimble County landfill to 2015 due to permitting issues of $21 million are remaining environmental variances. Transmission underspend of $25 million was due mainly to delayed spending on Cane Run U7, New Albany transmission work and line rating projects; Distribution variances of $37 million were driven by timing of circuit hardening, major substation projects, main replacement and gas riser projects and are expected to reverse by year end.
- Full year capital is projected to be $19 million lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.
- Lower O&M in September due primarily to $3 million of lower outside services and $7 million of lower materials and other non-labor costs.
- Lower O&M YTD due primarily to $9 million of labor savings, $11 million of lower outside services, $4 million of lower uncollectible accounts and $10 million of lower materials and other non-labor costs.

Major Developments

- On September 10 the combined LG&E/KU native load peaked at 6,434 MW, exceeding the previous peak for this summer of 6,409 MW that was set in July. This represents the first time that the summer peak was established in September.
- LG&E applied for, and received from the Louisville Metro Air Pollution Control District, a 6-month extension under the MATS regulations for completing the Cane Run Unit 7 project. The extension ties to LG&E's contract terms for final completion and acceptance testing of the new unit. LG&E previously received authorization for a one-year extension at Mill Creek.
- For the second consecutive year, LG&E and KU has been named as one of the top 10 utilities in economic development by Site Selection magazine. The selections were based on a number of criteria related to 2012 activity including new projects resulting in approximately 9,300 jobs and $1.7 billion in investment.
- KU is proceeding with efforts to improve its returns on equity (ROE) for its Old Dominion Power operations in Virginia and with the Kentucky municipal customers supplied under FERC-approved rates.
  - KU filed a Stipulation and Recommendation with the Virginia Staff agreeing to a $4.7 million revenue increase with new base rates going into effect on December 1, 2013 (one month earlier than requested).
  - KU filed a rate case with FERC to modify its wholesale power contracts and formula rates for its 12 municipal customers. KU testimony supports a 10.7 percent ROE and proposes a true-up component which effectively removes regulatory lag.

Significant Future Events

- LG&E and KU expects to make a filing with the Kentucky Public Service Commission in Q4 for a certificate of public convenience and necessity to build a new natural gas combined cycle (NGCC) unit for commercial operation in 2018. LG&E and KU also proposes to construct about a 10-megawatt solar facility at one of its existing generating stations. These projects do not materially impact LKE's 5-year capital plan; capital for the 2018 NGCC build was included in last year's business plan.

(1) Percentages represent a trailing twelve months.

(2) "Other" is typically comprised of the public authority customer class and KU's 12 full-requirements wholesale municipal customers.

(3) Excludes goodwill and other purchase accounting adjustments.

(4) Net of cost recovery mechanisms.

(5) The nine NERC Possible Violation Issues for YTD Actual are expected to be resolved through NERC's Find, Fix and Track ("FFT") process without financial penalty.

Income Statement: Actual vs. Budget and Forecast (Month)

September 2013

($ Millions)

	MTD				MTD			
	Actual	**Budget**	**Variance**	**Comments**	**Actual**	**Q2 Forecast**	**Variance**	**Comments**
Revenues:								
Electric Revenues	$ 215	$ 235	$ (19)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.	$ 215	$ 228	$ (12)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.
Gas Revenues	13	13	(0)		13	12	0	
Total Revenues	228	247	(20)		228	240	(12)	
Cost of Sales:								
Fuel Electric Costs	71	74	3		71	74	3	
Gas Supply Expenses	4	4	0		4	4	(0)	
Purchased Power	4	6	1		4	6	2	
Other Electric Cost	9	12	3		9	9	0	
Total Cost of Sales	89	96	7	Primarily decreased electric volumes and prices. Offset by unfavorable electric revenues above.	89	93	4	
Gross Margin:								
Electric Margin	131	143	(12)	Primarily $6m of lower energy revenues, as volumes were down 4% due to mild weather, and $5m of lower demand charge revenues.	131	139	(8)	Lower electric energy volumes due to unseasonably mild weather and economic conditions.
Gas Margin	8	8	(0)		8	8	0	
Total Gross Margin	139	151	(12)		139	147	(8)	
Operating Expenses:								
O&M	53	63	10	Primarily $3m of lower outside services and $7m of lower materials and other non-labor costs.	53	60	7	Lower outside services, materials and other nonlabor costs.
Depreciation & Amortization	28	28	1		28	27	(0)	
Taxes, Other than Income	4	4	0		4	4	0	
Total Operating Expenses	84	96	11		84	92	7	
Equity in earnings	-	(0)	0		-	0	(0)	
Other income	(0)	(0)	0		(0)	(0)	0	
EBIT	55	55	0		55	55	(0)	
Interest Expense	12	13	0		12	13	0	
Income from Ongoing Operations before income taxes	43	42	1		43	42	0	
Income Tax Expense	16	16	1		16	16	0	
Net Income (loss) from ongoing operations	**27**	**26**	**1**		**27**	**26**	**1**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	0	(0)	0		0	0	(0)	
Net Income (loss)	$ 27	$ 26	$ 1		$ 27	$ 27	$ 0	
KY Regulated Financing Costs	(3)	(2)	(0)		(3)	(3)	(0)	
KY Regulated Net Income	$ 24	$ 24	$ 0		$ 24	$ 24	$ 0	
Earnings Per Share	$ 0.04	$ 0.04	$ 0.00		$ 0.04	$ 0.03	$ 0.00	

Income Statement: Actual vs. Budget (YTD) September 2013

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 2,013	$ 2,103	$ (89)	Primarily lower electric energy volumes driven by unseasonably mild weather and economic conditions and lower demand charge revenues.
Gas Revenues	216	216	1	
Total Revenues	2,230	2,318	(89)	
Cost of Sales:				
Fuel Electric Costs	688	713	24	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.
Gas Supply Expenses	105	105	0	
Purchased Power	43	50	7	Lower purchases than originally planned.
Other Electric Cost	76	87	12	Lower electric volumes and ECR costs.
Total Cost of Sales	912	955	43	
Gross Margin:				
Electric Margin	1,206	1,252	(46)	Primarily $32m of lower energy revenues, as volumes were down 3% due to unseasonably mild temperatures, and $29m of lower demand charge revenues, partially offset by favorable margins of $13 million on retail rate mechanisms.
Gas Margin	112	111	1	
Total Gross Margin	1,318	1,363	(45)	
Operating Expenses:				
O&M	508	542	34	Primarily $9m of labor savings, $11m of lower outside services, $4m of lower uncollectible accounts and $10m of lower materials and other non-labor costs.
Depreciation & Amortization	246	252	6	Revised estimates based on delayed capital spend in 2012 and revised in-service dates for capital projects in 2013.
Taxes, Other than Income	36	36	0	
Total Operating Expenses	790	831	41	
Equity in earnings	-	(1)	1	
Other income	(6)	(7)	1	
EBIT	522	525	(3)	
Interest Expense	111	113	1	
Income from Ongoing Operations before income taxes	411	413	(2)	
Income Tax Expense	153	155	2	
Net Income (loss) from ongoing operations	**258**	**258**	**0**	
Non Operating Income	1	-	1	
Discontinued Operations	2	(1)	3	
Net Income (loss)	$ 261	257	$ 4	
KY Regulated Financing Costs	(33)	(30)	(3)	
KY Regulated Net Income	$ 227	$ 227	$ 1	
Earnings Per Share	$ 0.37	$ 0.37	$ (0.01)	

Income Statement: Forecast vs. Budget and Prior Forecast

September 2013

($ Millions)

	Full Year				Full Year			
	Forecast	Budget	Variance	Comments	Forecast	Q2 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 2,650	$ 2,753	$ (102)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.	$ 2,650	$ 2,706	$ (55)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.
Gas Revenues	315	313	2		315	315	(1)	
Total Revenues	2,965	3,065	(100)		2,965	3,021	(56)	
Cost of Sales:								
Fuel Electric Costs	902	928	25	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.	902	928	26	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.
Gas Supply Expenses	158	157	(1)		158	158	1	
Purchased Power	56	67	11	Lower purchases than originally planned and updated to more accurately reflect trend in actuals.	56	66	10	Lower purchases than originally planned and updated to more accurately reflect trend in actuals.
Other Electric Cost	103	119	17	Lower electric volumes.	103	103	0	
Total Cost of Sales	1,219	1,271	53		1,219	1,255	36	
Gross Margin:								
Electric Margin	1,590	1,638	(49)	Lower energy volumes due to unseasonably mild weather and economic conditions and lower demand charge revenues.	1,590	1,609	(20)	Lower electric energy volumes due to unseasonably mild weather in July and August and economic conditions.
Gas Margin	157	156	1		157	157	(0)	
Total Gross Margin	1,746	1,794	(48)		1,746	1,766	(20)	
Operating Expenses:								
O&M	693	721	28	Favorable labor and burdens, uncollectible accounts, outside services and materials.	693	704	11	Primarily a continued efforts to control costs.
Depreciation & Amortization	330	338	8	Revised estimates based on delayed capital spend in 2012 and revised in-service dates for capital projects in 2013.	330	329	(0)	
Taxes, Other than Income	48	48	(0)		48	48	0	
Total Operating Expenses	1,071	1,107	36		1,071	1,082	11	
Equity in earnings	-	(1)	1		-	0	(0)	
Other income	(8)	(8)	1		(8)	(7)	(0)	
EBIT	668	677	(10)		668	677	(10)	
Interest Expense	152	154	2		152	153	1	
Income from Ongoing Operations before income taxes	515	524	(8)		515	524	(9)	
Income Tax Expense	192	196	4		192	196	4	
Net Income (loss) from ongoing operations	**324**	**328**	**(4)**		**324**	**328**	**(3)**	
Non Operating Income	1	-	1		1	1	0	
Discontinued Operations	2	(1)	3		2	1	1	
Net Income (loss)	$ 326	$ 326	$ (0)		$ 326	$ 329	$ (3)	
KY Regulated Financing Costs	(41)	(37)	(4)		(41)	(40)	(1)	
KY Regulated Net Income	$ 285	$ 289	$ (4)		$ 285	$ 289	$ (3)	
Earnings Per Share	$ 0.46	$ 0.46	$ 0.00		$ 0.46	$ 0.46	$ (0.00)	

Electric Gross Margin

September 2013

($ Millions)

	MTD						YTD					
	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance
Base Electric Margin:						**$ (12)** ◆						**$ (59)** ◆
Energy Volumes (a)	2,638,359	2,741,329	(102,970)	$ -	$ (5)		24,968,477	25,738,777	(770,299)	$ -	$ (25)	
Energy Prices (a)					(1)						(7)	
Customer Charges (Avg. Customers)	936,089	946,752	(10,663)		-		935,408	945,112	(9,704)		1	
Demand Charges (b)	43	48			(5)		355	384			(29)	
ECR:						**(0)** ◆						**(2)** ◆
Average Rate Base	$ 805	$ 929	$ (124)	10.43%	$ (1.0)		$ 648	$ 742	$ (94)	10.44%	$ (6.5)	
Cost of Capital	10.26%	10.43%	-0.17%	$ 805	(0.1)		10.29%	10.44%	-0.14%	$ 648	(0.6)	
Jurisdictional Factor	90.94%	90.10%	0.84%	$ 805	0.1		89.09%	88.97%	0.12%	$ 648	0.1	
Other					0.7						5.0	
DSM:						**1** ●						**5** ●
Program Expense (Revenue Net of Expense)	$ 0.1	$ 0.1			$ -		$ 0.5	$ 0.4			$ 0.1	
Lost Sales	1.5	1.0			0.5		12.5	9.1			3.4	
Incentive	0.1	0.1			-		0.9	0.7			0.2	
Balancing Adjustment	0.2	-			0.2		0.9	-			0.9	
Net Fuel Recovery	$ (0.3)	$ (0.4)				**0** ●	$ 1	$ (5)				**6** ●
Purchase Power Demand	(2.2)	(2.5)				**0** ●	(21.3)	(22.7)				**1** ●
Transmission	(0.5)	1.0				**(2)** ◆	7.4	7.8				**(0)** ◆
Other	(1.2)	(1.5)				**0** ●	(14.2)	(16.3)				**2** ●
Retail Margin Variance						**(12)** ◆						**(47)** ◆
Off-System Margin Variance						**-** ●						**1** ●
Electric Margin Variance						**$ (12)** ◆						**$ (46)** ◆

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 38	774,453	$ 48.95	$ 43	884,477	$ 48.83	$ (5) ◆	$ (5) ◆	$ 0 ●
Commercial	20	655,638	30.62	22	672,934	31.96	(1) ◆	(1) ◆	(1) ◆
Industrial	7	797,605	8.93	7	792,036	8.90	- ●	- ●	- ●
Municipals	1	152,628	5.56	1	153,127	4.69	0 ●	- ●	0 ●
Other	6	258,034	21.40	5	238,755	22.56	0 ●	0 ●	(0) ◆
Native Load Total	**$ 72**	**2,638,359**	**$ 27.09**	**$ 78**	**2,741,329**	**$ 28.40**	**$ (7)** ◆	**$ (5)** ◆	**$ (1)** ◆

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 398	8,176,135	$ 48.63	$ 411	8,473,482	$ 48.51	$ (14) ◆	$ (14) ◆	$ 1 ●
Commercial	186	5,921,638	31.42	198	6,154,642	32.11	(12) ◆	(8) ◆	(4) ◆
Industrial	64	7,316,690	8.72	66	7,432,363	8.86	(2) ◆	(1) ◆	(1) ◆
Municipals	7	1,429,716	4.99	7	1,479,110	4.69	0 ●	(0) ◆	0 ●
Other	46	2,124,299	21.71	51	2,199,180	23.17	(5) ◆	(2) ◆	(3) ◆
Native Load Total	**$ 701**	**24,968,477**	**$ 28.06**	**$ 732**	**25,738,777**	**$ 28.46**	**$ (32)** ◆	**$ (25)** ◆	**$ (7)** ◆

(b) Demand Analysis (net of base ECR revenue):	MTD			YTD		
$mil	Act	Bud	Variance	Act	Bud	Variance
Commercial	14	18	(3)	121	135	(15)
Industrial	17	20	(3)	147	161	(14)
Municipals	5	5	0	37	40	(3)
Other	7	6	1	51	48	3
Native Load Total	**43**	**48**	**(5)**	**355**	**384**	**(29)**

Weather Statistics	MTD			YTD		
	Act	+/- Bud		Act	+/- Bud	
Heating Degree Days - Louisville	10	(23)	-70%	2,744	107	4%
Heating Degree Days - Lexington	17	(31)	-65%	2,912	25	1%
Cooling Degree Days - Louisville	201	18	10%	1,404	(37)	-3%
Cooling Degree Days - Lexington	163	18	12%	1,200	35	3%

Gas Gross Margin

September 2013

($ Millions)

	MTD				YTD			
	Actual	**Budget**	**Subtotal**	**Margin Variance**	**Actual**	**Budget**	**Subtotal**	**Margin Variance**
Gas Base Service Charge	**$ 5**	**$ 5**		**$ - ●**	**$ 48**	**$ 45**		**$ 2 ●**
Gas Supply Costs								
Gas Supply Costs	(4)	(3)	$ (1)		(106)	(98)	$ (8)	
GSC Revenue	4	3	1		105	98	7	
Net Gas Supply Costs				**(0) ◆**				**$ (2) ◆**
Retail Gas (a)	**2**	**2**		**(0) ◆**	**60**	**56**		**$ 4 ●**
Wholesale Gas (a)	**-**	**-**		**- ●**	**-**	**-**		**$ - ●**
DSM	**(0)**	**(0)**		**0 ●**	**-**	**(2)**		**$ 2 ●**
GLT	**0**	**0**		**- ●**	**2**	**2**		**$ (0) ◆**
WNA	**-**	**-**		**- ●**	**(3)**	**-**		**$ (3) ◆**
Other Margin	**0**	**0**		**(0) ◆**	**1**	**2**		**$ (2) ◆**
Gas Margin Variance				**$ (0) ◆**				**$ 1 ●**

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 1	390,991	$ 2.64	$ 1	433,894	$ 2.68	$ (0) ◆	$ (0) ◆	$ - ●
Commercial	-	269,362	-	1	286,432	2.08	(1) ◆	- ●	(1) ◆
Industrial	0	235,050	1.00	0	52,215	1.85	0 ●	0 ●	(0) ◆
Public Authority	0	33,075	1.83	0	36,322	1.81	- ●	- ●	- ●
Transportation	1	735,849	0.96	0	707,571	0.42	0 ●	- ●	0 ●
Ultimate Consumer	$ 2	1,664,327	$ 1.22	$ 2	1,516,434	$ 1.46	$ (0) ◆	$ 0 ●	$ (0) ◆

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume (Mcf)**	**Price ($/Mcf)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 37	13,836,533	$ 5.28	$ 36	13,983,768	$ 5.27	$ 0 ●	$ (0) ◆	$ 1 ●
Commercial	12	6,218,655	2.03	13	6,251,764	4.13	(1) ◆	- ●	(1) ◆
Industrial	2	1,033,052	2.70	1	660,101	3.70	0 ●	1 ●	(0) ◆
Public Authority	2	1,076,851	3.79	2	1,122,904	3.77	(0) ◆	(0) ◆	- ●
Transportation	7	8,631,422	1.80	4	8,187,360	0.86	4 ●	0 ●	4 ●
Ultimate Consumer	$ 60	30,796,513	$ 15.60	$ 56	30,205,897	$ 17.73	$ 4 ●	$ 0 ●	$ 3 ●

O&M **September 2013**

($ Millions)

	MTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 17	$ 20	$ 3	$ -	$ 0	$ 2	$ 1	$ 2	$ -	$ (2)
Project Engineering	0	0	0	-	0	-	(0)	(0)	-	0
Transmission	2	2	0	-	(0)	-	0	(0)	-	0
Energy Supply and Analysis	1	1	0	-	0	-	0	0	-	0
Electric Distribution	5	6	1	-	(1)	-	0	1	(0)	1
Gas Distribution	3	3	1	-	0	-	1	0	(0)	(0)
Customer Services	7	8	1	-	0	-	(0)	0	(0)	0
Chief Operations Officer	**34**	**40**	**6**	**-**	**0**	**2**	**2**	**3**	**(0)**	**(1)**
Information Technology	4	5	1	-	1	-	0	(0)	-	(0)
General Counsel	3	4	1	-	0	-	1	(0)	-	0
Human Resources	1	1	0	-	0	-	0	0	-	0
Supply Chain	0	0	0	-	0	-	0	(0)	-	0
Chief Administrative Officer	**7**	**9**	**2**	**-**	**1**	**-**	**1**	**(0)**	**-**	**0**
Chief Financial Officer	**1**	**2**	**0**	**-**	**0**	**-**	**(0)**	**0**	**-**	**0**
Corporate	**10**	**12**	**2**	**2**	**(0)**	**-**	**0**	**0**	**0**	**(0)**
O&M Total MTD	**$ 53**	**$ 63**	**$ 10**	**$ 2**	**$ 1**	**$ 2**	**$ 3**	**$ 3**	**$ 0**	**$ (1)**

	YTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 160	$ 170	$ 10	$ -	$ 4	$ 11	$ 3	$ 3	$ -	$ (11)
Project Engineering	0	1	0	-	0	-	(0)	(0)	-	0
Transmission	22	23	1	-	(0)	-	1	0	-	0
Energy Supply and Analysis	6	8	1	-	0	-	0	0	(0)	1
Electric Distribution	52	53	1	-	(0)	-	(2)	3	(0)	0
Gas Distribution	22	25	3	-	0	-	2	(0)	(0)	0
Customer Services	60	69	9	-	2	-	2	0	4	1
Chief Operations Officer	**323**	**348**	**25**	**-**	**7**	**11**	**7**	**6**	**4**	**(10)**
Information Technology	35	37	2	-	2	-	(1)	(0)	-	0
General Counsel	21	25	4	-	0	-	4	0	-	0
Human Resources	5	5	1	-	0	-	0	0	-	0
Supply Chain	2	3	0	-	0	-	0	0	-	0
Chief Administrative Officer	**64**	**71**	**7**	**-**	**3**	**-**	**3**	**(0)**	**-**	**1**
Chief Financial Officer	**13**	**14**	**1**	**-**	**0**	**-**	**(0)**	**0**	**-**	**1**
Corporate	**109**	**109**	**1**	**(2)**	**(0)**	**-**	**3**	**1**	**1**	**(2)**
O&M Total YTD	**$ 508**	**$ 542**	**$ 34**	**$ (2)**	**$ 10**	**$ 11**	**$ 12**	**$ 7**	**$ 4**	**$ (9)**

	Full Year			Variances						
	Forecast	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 222	$ 227	$ 6	$ -	$ 5	$ 2	$ 2	$ (3)	$ -	$ 0
Project Engineering	1	1	0	-	(0)	-	(0)	(0)	-	0
Transmission	29	29	0	-	(0)	-	3	(2)	-	(0)
Energy Supply and Analysis	9	10	1	-	0	-	0	0	-	0
Electric Distribution	69	69	0	-	(1)	-	0	1	-	(0)
Gas Distribution	31	34	3	-	0	-	2	1	-	(0)
Customer Services	82	91	9	-	3	-	3	0	4	(1)
Chief Operations Officer	**442**	**461**	**19**	**-**	**7**	**2**	**10**	**(4)**	**4**	**(0)**
Information Technology	48	50	2	-	2	-	(1)	(0)	-	1
General Counsel	30	34	4	-	0	-	3	(0)	-	0
Human Resources	7	7	1	-	0	-	0	(0)	-	0
Supply Chain	3	3	0	-	0	-	0	-	-	0
Chief Administrative Officer	**88**	**95**	**7**	**-**	**3**	**-**	**3**	**(0)**	**-**	**1**
Chief Financial Officer	**18**	**19**	**1**	**-**	**0**	**-**	**0**	**-**	**-**	**1**
Corporate	**146**	**146**	**0**	**(2)**	**0**	**-**	**2**	**(0)**	**1**	**(0)**
O&M Total Full Year	**$ 693**	**$ 721**	**$ 28**	**$ (2)**	**$ 11**	**$ 2**	**$ 15**	**$ (4)**	**$ 5**	**$ 2**

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)
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Witness: K Blake

Financing Activities September 2013

($ Millions)

Balance Sheet	MTD			YTD			Full Year		
	Actual	Budget	Variance	Actual	Budget	Variance	Forecast	Budget	Variance
PCB									
Beg Bal	$ 931.8	$ 931.8	$ -	$ 932.0	$ 932.0	$ 0.0	$ 932.0	$ 932.0	$ -
End Bal	931.8	931.8	-	931.8	931.8	-	931.7	931.7	(0.0)
Ave Bal	**$ 931.8**	**$ 931.8**	**$ -**	**$ 931.9**	**$ 931.9**	**$ (0.0)**	**$ 931.8**	**$ 931.8**	**$ (0.0)**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 7.8**	**$ 10.3**	**$ 2.4**	**$ 10.6**	**$ 13.6**	**$ 3.0**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.11%**	**1.45%**	**0.34%**	**1.13%**	**1.46%**	**0.33%**
FMB/Sr Nts									
Beg Bal	$ 3,143.9	$ 3,143.9	$ (0.0)	$ 3,142.8	$ 3,142.8	$ 0.0	$ 3,142.8	$ 3,142.8	$ 0.0
End Bal	3,144.0	3,144.0	(0.0)	3,144.0	3,144.0	(0.0)	3,644.4	3,694.4	50.0
Ave Bal	**$ 3,144.0**	**$ 3,144.0**	**$ (0.0)**	**$ 3,143.4**	**$ 3,143.5**	**$ 0.1**	**$ 3,227.0**	**$ 3,235.3**	**$ 8.3**
Interest Exp	**$ 9.6**	**$ 9.6**	**$ 0.0**	**$ 86.0**	**$ 86.0**	**$ (0.0)**	**$ 120.5**	**$ 120.2**	**$ (0.3)**
Rate	**0.00%**	**0.00%**	**0.00%**	**3.61%**	**3.61%**	**0.00%**	**3.73%**	**3.72%**	**-0.02%**
Short-term Debt									
Beg Bal	$ 279.5	$ 509.1	$ 229.6	$ 149.7	$ 149.7	$ (0.0)	$ 149.7	$ 149.7	$ (0.0)
End Bal	263.7	517.4	253.7	263.7	517.4	253.7	209.4	176.3	(33.1)
Ave Bal	**$ 271.6**	**$ 513.2**	**$ 241.6**	**$ 206.7**	**$ 371.0**	**$ 164.3**	**$ 290.1**	**$ 359.0**	**$ 69.0**
Interest Exp	**$ 0.2**	**$ 0.2**	**$ 0.1**	**$ 1,689.7**	**$ 1,770.9**	**$ 81.2**	**$ 2.4**	**$ 1.2**	**$ (1.2)**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.08%**	**0.63%**	**-0.45%**			
Total End Bal	**$ 4,339.5**	**$ 4,593.2**	**$ 253.7**	**$ 4,339.5**	**$ 4,593.2**	**$ 253.7**	**$ 4,785.5**	**$ 4,802.4**	**$ 16.9**
Total Average Bal	**$ 4,347.3**	**$ 4,588.9**	**$ 241.6**	**$ 4,282.0**	**$ 4,446.3**	**$ 164.3**	**$ 4,448.9**	**$ 4,526.2**	**$ 77.3**
Total Expense Excl I/C	**$ 12.3**	**$ 12.6**	**$ 0.3**	**$ 111.2**	**$ 112.5**	**$ 1.4**	**$ 152.2**	**$ 153.8**	**$ 1.7**
Rate	**3.63%**	**3.52%**	**-0.11%**	**3.42%**	**3.34%**	**-0.09%**	**3.42%**	**3.40%**	**-0.02%**

Credit Facilities ($ Millions)	**Committed Capacity**	**Borrowed**	**Letters of Credit Issued**	**Unused Capacity**
LKE	$ 300	$ 52		$ 248
LG&E	500	72		428
KU	598	140	$ 198	260
TOTAL	$ 1,398	$ 264	$ 198	$ 936

Credit Metrics ($ Millions)	**YTD**		**Full Year**	
	Actual	**+/- Bud**	**Forecast**	**+/- Bud**
FFO to Debt - LG&E	37.0%	+0.10	29.3%	+0.03
FFO to Debt - KU	30.6%	+0.05	25.8%	+0.00
Debt to EBITDA - LG&E (1)	2.79	-0.53	3.28	-0.04
Debt to EBITDA - KU (1)	3.51	-0.15	3.69	+0.02
Debt to Capitalization - LG&E (2)	43.4%	-0.02	47.0%	-0.00
Debt to Capitalization - KU (2)	45.7%	-0.01	47.1%	+0.00

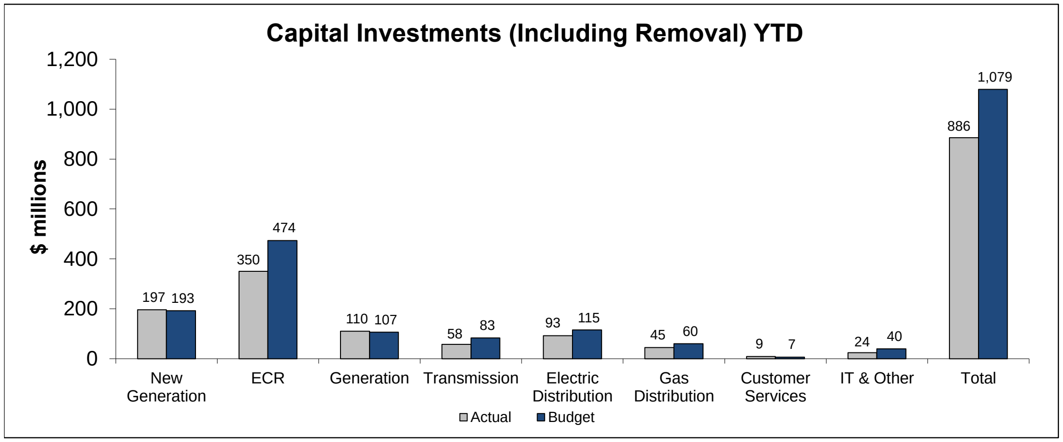
(1) Actuals represent a trailing 12 months

(2) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet September 2013

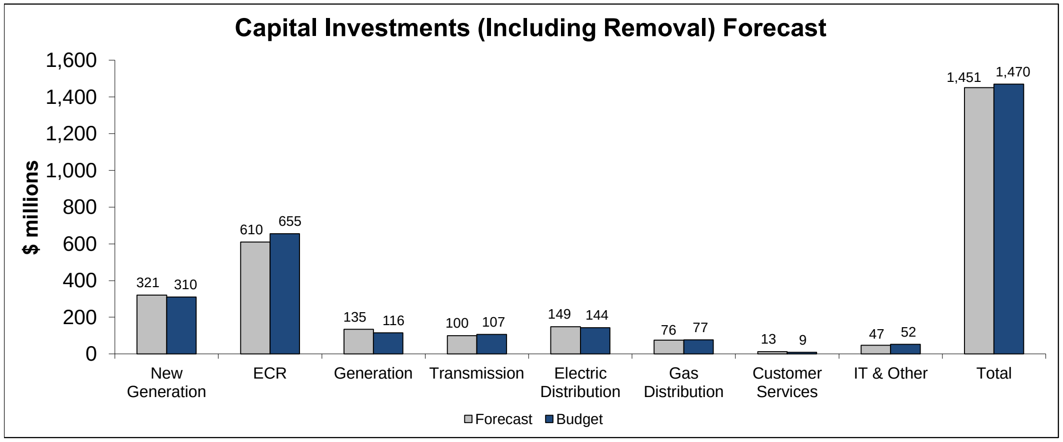
($ Millions)

	YTD	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 21	$ 10	$ 11	See cash flow statement for details.
Accounts Receivable (Trade)	359	322	37	Due primarily to tariff rate variance in receivable logic and extended due date granted in rate case.
Inventory	275	254	21	Primarily an increase in fuel ($16m) and materials and supplies ($5m).
Deferred Income Taxes	20	13	6	
Prepayments and other current assets	43	65	(22)	Budget included $14m for forward hedging swaps entered into in Nov. 2012 compared to actuals of zero due to settlement in Sept.; also $5m for provision for bad debts above plan.
Total Current Assets	718	664	53	
Property, Plant, and Equipment	9,064	9,142	(78)	See capital chart for details.
Intangible Assets	232	233	(1)	
Other Property and Investments	1	1	1	
Regulatory Assets	595	627	(32)	Primarily interest rate swaps ($18m) and decrease in FAC ($16m).
Goodwill	997	997	-	
Other Long-term Assets	96	103	(7)	
Total Assets	**$ 11,702**	**$ 11,767**	**$ (65)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 314	$ 204	$ 110	Primarily differences in capex accrual and an increase in retainage fees and fuel volumes.
Accounts Payable - Affiliated Company	-	(0)	0	
Customer Deposits	49	48	1	
Derivative Liability	18	5	13	Primarily due to short-term derivative liability from forward hedges with PPL as counterparty ($14m).
Accrued Taxes	109	40	69	Timing of tax payments and accruals in actuals vs. budget.
Other Current Liabilities	156	147	10	Credit Cash Balance over plan ($4m); Accr Sal & Ben over plan ($3m)
Total Current Liabilities	646	443	203	
Debt - Affiliated Company	-	-	-	
Debt	4,339	4,593	(254)	Less short-term debt issued than budgeted ($281m) due to lower capital spend, partially offset by notes payable to PPL ($27m). See Financing Activities page for more details.
Total Debt	4,339	4,593	(254)	
Deferred Tax Liabilities	651	684	(32)	Timing of recording of deferred taxes in actuals vs. budget.
Investment Tax Credit	136	134	1	
Accumulated Provision for Pension and Related Benefits	267	272	(5)	
Asset Retirement Obligation	245	130	115	ARO unplanned revaluation.
Regulatory Liabilities	1,056	990	66	Primarily due to short-term derivative asset gain from forward hedges entered into in Nov. 2012 and settled in Sept. 2013 with PPL as counterparty ($84m); partially offset by loss from hedges entered into in Sept. 2013 with PPL as counterparty ($14m).
Derivative Liability	37	54	(17)	Forward hedges with PPL as counterpary entered into in Sept. 2013.
Other Liabilities	249	238	11	Long-term project engineering retention fee balances over Plan.
Total Deferred Credits and Other Liabilities	2,641	2,501	140	
Equity	4,075	4,229	(154)	
Total Liabilities and Equity	**$ 11,702**	**$ 11,767**	**$ (65)**	



Capital Investments (Including Removal) YTD

Capital was $193m lower than budget YTD due mainly to slower than expected mobilization for Mill Creek of $55m and Ghent environmental air work of $21m. Spending delays on Brown landfill of $24m and the delay of Trimble County landfill to 2015 due to permitting issues of $21m are remaining environmental variances. Transmission underspend of $25m was due mainly to delayed spending on Cane Run U7, New Albany transmission work and line rating projects; Distribution variances of $37m were driven by timing of circuit hardening, major substation projects, main replacement and gas riser projects and are expected to reverse by year end.



Capital Investments (Including Removal) Forecast

Capital is projected to be $19m lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.

Cash Flow

September 2013

YTD	Actual	Budget	Variance	Comments
Net income	261	257	4	
Depreciation	268	265	4	
Deferred tax expense	99	137	-38	Differences in how annual estimates are spread in actuals vs. budget.
Other Balance Sheet Movements	114	-157	271	Primarily forward starting swaps settlement and increases in accrued taxes and other deferred credits.
Funds From Operations	**743**	**502**	**241**	
Changes in accounts receivables	-66	-29	-37	Tariff rate variance in receivable logic, extended due date granted in rate case.
Changes in inventories	1	20	-19	Increase in fuel volumes and materials and supplies.
Changes in accounts payable	35	78	-42	Decrease in fuel usage and other.
Change in Working Capital	**-30**	**68**	**-98**	
Operating Cash flow	**713**	**570**	**143**	
Capex	-891	-1,159	268	See Capex Charts for details.
Other Investing	12	0	12	Primarily collateral deposit for swaps.
Loans to Affiliates	0	0	0	
Investing Cash flow	**-879**	**-1,159**	**280**	
Dividends	-116	-93	-23	Higher dividends and lower equity infusions due to lower capital spend projected than budgeted.
Equity Infusion	146	280	-134	Higher dividends and lower equity infusions due to lower capital spend projected than budgeted.
Net Borrowings	114	368	-254	Higher dividends and lower equity infusions due to lower capital spend projected than budgeted.
Other	0	0	0	
Financing Cash flow	**144**	**555**	**-411**	
Net increase (decrease) in cash	**-22**	**-34**	**12**	

Full Year	FC	Budget	Variance	Comments
Net income	326	326	0	
Depreciation, amortization and impairments	354	356	-2	
Deferred tax expense	164	178	-14	Differences in YTD actual deferred taxes vs. budget.
Other Balance Sheet Movements	-30	-204	174	Includes increases in credit cash balance and accrued taxes, as well as decreases in regulatory assets and deferred tax assets and forward starting swaps settlement.
Funds From Operations	**814**	**656**	**158**	
Changes in accounts receivables	-117	-35	-83	Tariff rate variance in receivable logic, extended due date granted in rate case.
Changes in inventories	-11	15	-26	Increase in fuel volumes.
Changes in accounts payable	136	113	23	Differences in capex accrual.
Change in Working Capital	**7**	**94**	**-86**	
Operating Cash flow	**821**	**750**	**71**	
Capex	-1,510	-1,576	66	Revised cash adjustment ($47m) and delay in Trimble County landfill to 2015 ($12m).
Other Investing	12	0	12	Primarily collateral deposit for swaps.
Loans to Affiliates	0	0	0	
Investing Cash flow	**-1,498**	**-1,576**	**78**	
Dividends	-203	-157	-46	Lower equity infusions and debt due to lower capital spend projected than budgeted.
Equity Infusion	287	374	-87	Lower equity infusions and debt due to lower capital spend projected than budgeted.
Net Borrowings	560	577	-17	Lower equity infusions and debt due to lower capital spend projected than budgeted.
Other	0	0	0	
Financing Cash flow	**644**	**793**	**-149**	
Net increase (decrease) in cash	**-33**	**-33**	**0**	

Performance Report

October 2013

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Kentucky Regulated Dashboard

October 2013

Operational Metrics	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	3.43	0.77	1.51	1.42	N/A	1.35
Employee lost-time incidents	2	1	3	5	N/A	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,629	2,537	28,501	29,416	34,213	35,128
Utility EFOR	10.5%	5.1%	7.7%	5.1%	N/A	5.1%
Utility EAF	70.1%	75.5%	81.2%	86.9%	N/A	87.08%
Combined SAIFI	0.09	0.10	0.88	1.08	N/A	1.22
Combined SAIDI (minutes)	7.57	7.38	78.94	98.71	N/A	109.60
Steam Fleet Commercial Availability	88.7%	N/A	91.5%	91.3%	N/A	N/A
GwH Sales						
Residential	646	689	8,823	9,163	10,595	10,912
Commercial	651	637	6,573	6,791	7,792	8,063
Industrial	831	808	8,148	8,240	9,786	9,891
Municipals	141	149	1,571	1,628	1,878	1,944
Other	251	232	2,375	2,432	2,805	2,901
Off-System Sales	49	8	369	354	494	465
Total	2,569	2,522	27,859	28,607	33,349	34,175
Weather-Normalized Sales Growth[(1)]			**W-N**			
Residential			1.19%			
Commercial			-1.22%			
Industrial			0.34%			
Other			-1.16%			
Total			0.03%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[(2)]	6.8%	5.7%	10.1%	9.8%	9.8%	9.6%
Electric Margins	$127	$123	$1,333	$1,375	$1,591	$1,638
Gas Margins	$10	$10	$122	$121	$157	$156
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$34	$34	$271	$260	$321	$310
ECR	64	65	415	540	610	655
Generation	22	22	92	96	135	117
Transmission	14	9	72	91	100	107
Electric Distribution	17	11	110	126	149	144
Gas Distribution	10	6	54	66	76	77
Customer Services	2	1	11	8	13	9
IT and Other	5	4	30	44	47	51
Total	$168	$152	$1,055	$1,231	$1,451	$1,470
O&M ($ millions)[(3)]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$43	$41	$366	$389	$440	$461
Administrative	$7	8	$70	$79	87	95
Finance	$2	2	$15	$16	17	19
Burdens & Other Charges	$10	12	$119	$121	144	146
Total	$62	$63	$570	$605	$688	$721
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,392	3,436	3,392	3,436	3,423	3,435
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	2	0	11	10	N/A	14
NERC Possible Violations[(4)]	0	0	9	24	N/A	24

Variance Explanations

- The generation fleet's EAF and EFOR are unfavorable to budget due primarily to Mill Creek Unit 3 Turbine crossover expansion joint failure, Ghent Unit 4 cooling tower header failure, Trimble County Unit 2 low pressure turbine bearing failure and Cane Run Unit 4 generator rotor winding shorts.
- Lower margins YTD due primarily to $33 million of lower energy revenues, as volumes were down 3% due to unseasonably mild temperatures, and $29 million of lower demand charge revenues, partially offset by favorable margins of $21 million on retail rate mechanisms, off-system sales and gas.
- Capital was $176m lower than budget YTD due mainly to timing delays to be largely made up in November and December – see Full Year Forecast below.
- Full year capital is projected to be $19 million lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.
- Lower O&M YTD due primarily to $12 million of labor savings, $6 million of lower outside services, $4 million of lower uncollectible accounts and $13 million of lower materials and other nonlabor costs.

Major Developments

- Based on the federal government shutdown and consistent with LKE's vision to empower economic vitality and quality of life, LKE announced that it will match $2 for every $1 (extending beyond the previous $1 for $1 match) donated by residential customers to its heating assistance programs.
- Cane Run Unit 7 achieved a significant milestone as the combustion turbines and generators have been delivered to the site. The Heat Recovery Steam Generator drums and tube bundle sections have also begun to arrive by barge delivery in Louisville, staged near the plant site.
- LKE announced a financing agreement with local banks to fund $75 million in working capital needs. The agreement also supports regional economic development throughout the LG&E and KU service territories as it capitalizes on substantial local bank deposits and offers investment-grade lending opportunities to bank participants.
- LG&E and KU filed a prospectus in November each selling $250 million of 4.650 percent first mortgage bonds due November 15, 2043. The bonds have a spread to benchmark Treasury of 90 basis points, the lowest 30 year utility spread seen since April, and were offered at a price of 99.280 percent. LG&E and KU had hedged the underlying treasury rate risk earlier which will reduce the effective rate by about 58 bps.

Significant Future Events

- LKE expects to make a filing with the Kentucky Public Service Commission in Q4 for a CPCN to build a new NGCC unit at the Green River site for commercial operation in 2018. The filing also proposes to construct about a 10-megawatt solar facility at its Brown generating station.
- In addition, LG&E is expected to file in Q4 a new permit for the Trimble County landfill. In May, the Kentucky Division of Waste Management notified LG&E of its intent to deny the permit application. The new permit application will represent the next lowest cost alternate location which is also on existing plant property.

(1) Percentages represent a trailing twelve months.

(2) Excludes goodwill and other purchase accounting adjustments.

(3) Net of cost recovery mechanisms.

(4) The nine NERC Possible Violation Issues for YTD Actual are expected to be resolved through NERC's Find, Fix and Track ("FFT") process without financial penalty.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget and Forecast (Month) October 2013

($ Millions)

	MTD				MTD			
	Actual	Budget	Variance	Comments	Actual	Q3 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 204	$ 206	$ (2)		$ 204	$ 200	$ 4	
Gas Revenues	19	18	1		19	19	(0)	
Total Revenues	223	224	(1)		223	219	4	
Cost of Sales:								
Fuel Electric Costs	64	67	3		64	67	3	
Gas Supply Expenses	9	7	(1)		9	9	0	
Purchased Power	5	6	1		5	5	(1)	
Other Electric Cost	8	10	3		8	8	0	
Total Cost of Sales	86	91	5	Due primarily to increased fuel recoveries.	86	88	2	
Gross Margin:								
Electric Margin	127	123	4		127	121	6	Due primarily to increased fuel recoveries due partially from a change in the FAC rate.
Gas Margin	10	10	(0)		10	10	0	
Total Gross Margin	137	133	4		137	131	6	
Operating Expenses:								
O&M	62	63	1		62	70	8	Includes $5m of permanent cost savings identified and $3m of delayed spending.
Depreciation & Amortization	28	28	1		28	28	0	
Taxes, Other than Income	4	4	0		4	4	0	
Total Operating Expenses	93	95	2		93	102	8	
Equity in earnings	-	(0)	0		-	-	-	
Other income	(1)	(1)	(0)		(1)	(0)	(0)	
EBIT	43	37	6		43	29	14	
Interest Expense	12	13	0		12	13	0	
Income from Ongoing Operations before income taxes	31	25	6		31	16	14	
Income Tax Expense	11	9	(2)		11	6	(6)	
Net Income (loss) from ongoing operations	**19**	**16**	**3**		**19**	**11**	**9**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	(0)	(0)	0		(0)	0	(0)	
Net Income (loss)	$ 19	$ 16	$ 3		$ 19	$ 11	$ 9	
KY Regulated Financing Costs	(3)	(2)	(0)		(3)	(3)	(0)	
KY Regulated Net Income	$ 16	$ 13	$ 2		$ 16	$ 8	$ 8	
Earnings Per Share	$ 0.02	$ 0.02	$ 0.00		$ 0.02	$ 0.01	$ 0.01	

Income Statement: Actual vs. Budget (YTD) October 2013

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,217	$ 2,309	$ (91)	Due to lower residential and commercial electric consumption volumes, lower demand charges and other customer/tariff mix changes partially offset by higher recoveries from fuel adjustment and demand side management rate mechanisms.
Gas Revenues	235	233	2	
Total Revenues	2,453	2,542	(90)	
Cost of Sales:				
Fuel Electric Costs	753	779	27	
Gas Supply Expenses	113	112	(1)	
Purchased Power	48	57	8	Lower purchases than originally planned.
Other Electric Cost	83	98	15	
Total Cost of Sales	998	1,046	49	Due to lower residential and commercial electric consumption volumes, lower demand charges and other customer/tariff mix changes partially offset by higher recoveries from fuel adjustment and demand side management rate mechanisms.
Gross Margin:				
Electric Margin	1,333	1,375	(42)	Due to lower residential and commercial electric consumption volumes, lower demand charges and other customer/tariff mix changes partially offset by higher recoveries from fuel adjustment and demand side management rate mechanisms.
Gas Margin	122	121	1	
Total Gross Margin	1,455	1,496	(41)	
Operating Expenses:				
O&M	570	605	35	Primarily $12m of labor savings, $6m of lower outside services, $4m of lower uncollectible accounts and $13m of lower materials and other nonlabor costs.
Depreciation & Amortization	274	281	7	Revised estimates based on delayed capital spend in 2012 and revised in-service dates for capital projects in 2013.
Taxes, Other than Income	39	40	1	
Total Operating Expenses	883	925	42	
Equity in earnings	-	(1)	1	
Other income	(7)	(7)	1	
EBIT	565	562	3	
Interest Expense	124	125	2	
Income from Ongoing Operations before income taxes	442	437	4	
Income Tax Expense	164	164	(1)	
Net Income (loss) from ongoing operations	**277**	**274**	**4**	
Non Operating Income	1	-	1	
Discontinued Operations	2	(1)	3	
Net Income (loss)	$ 280	272	$ 7	
KY Regulated Financing Costs	(36)	(32)	(4)	
KY Regulated Net Income	$ 244	$ 240	$ 4	
Earnings Per Share	$ 0.39	$ 0.39	$ 0.00	

Income Statement: Forecast vs. Budget and Prior Forecast — October 2013

($ Millions)

	Full Year				Full Year			
	Forecast	Budget	Variance	Comments	Forecast	Q3 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 2,650	$ 2,753	$ (103)	Due to lower residential and commercial electric consumption volumes, lower demand charges and other customer/tariff mix changes partially offset by higher recoveries from fuel adjustment and demand side management rate mechanisms.	$ 2,650	$ 2,650	$ (1)	
Gas Revenues	315	313	2		315	315	(0)	
Total Revenues	2,964	3,065	(101)		2,964	2,965	(1)	
Cost of Sales:								
Fuel Electric Costs	900	928	28		900	902	3	
Gas Supply Expenses	158	157	(1)		158	158	0	
Purchased Power	57	67	11	Lower purchases than originally planned and updated to more accurately reflect trend in actuals.	57	56	(1)	
Other Electric Cost	103	119	17		103	103	0	
Total Cost of Sales	1,216	1,271	55	Due to lower residential and commercial electric consumption volumes, lower demand charges and other customer/tariff mix changes partially offset by higher recoveries from fuel adjustment and demand side management rate mechanisms.	1,216	1,219	2	
Gross Margin:								
Electric Margin	1,591	1,638	(47)	Due to lower residential and commercial electric consumption volumes, lower demand charges and other customer/tariff mix changes partially offset by higher recoveries from fuel adjustment and demand side management rate mechanisms.	1,591	1,590	1	
Gas Margin	157	156	1		157	157	0	
Total Gross Margin	1,748	1,794	(46)		1,748	1,746	2	
Operating Expenses:								
O&M	688	721	33	Favorable labor and burdens, uncollectible accounts, outside services and materials.	688	693	5	Primarily a continued efforts to control costs.
Depreciation & Amortization	330	338	8	Revised estimates based on delayed capital spend in 2012 and revised in-service dates for capital projects in 2013.	330	330	0	
Taxes, Other than Income	48	48	0		48	48	0	
Total Operating Expenses	1,066	1,107	42		1,066	1,071	5	
Equity in earnings	-	(1)	1		-	-	-	
Other income	(8)	(8)	1		(8)	(8)	(0)	
EBIT	674	677	(3)		674	668	7	
Interest Expense	152	154	2		152	152	0	
Income from Ongoing Operations before income taxes	522	524	(1)		522	515	7	
Income Tax Expense	194	196	1		194	192	(3)	
Net Income (loss) from ongoing operations	**328**	**328**	**0**		**328**	**324**	**4**	
Non Operating Income	1	-	1		1	1	0	
Discontinued Operations	2	(1)	3		2	2	0	
Net Income (loss)	$ 330	$ 326	$ 4		$ 330	$ 326	$ 4	
KY Regulated Financing Costs	(41)	(37)	(4)		(41)	(41)	-	
KY Regulated Net Income	$ 289	$ 289	$ 0		$ 289	$ 285	$ 4	
Earnings Per Share	$ 0.46	$ 0.46	$ 0.00		$ 0.46	$ 0.46	$ -	

Electric Gross Margin — October 2013

($ Millions)

	MTD						YTD					
	Actual	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**	**Actual**	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**
Base Electric Margin:						**$ (2)** ◆						**$ (61)** ◆
Energy Volumes (a)	2,520,280	2,514,081	6,200	$ -	$ (1)		27,488,757	28,252,857	(764,100)	$ -	$ (26)	
Energy Prices (a)					(0)						(7)	
Customer Charges (Avg. Customers)	937,208	948,347	(11,139)		0		935,588	945,435	(9,848)		2	
Demand Charges (b)	39	39			(1)		394	423			(29)	
ECR:						**(0)** ◆						**(3)** ◆
Average Rate Base	$ 840	$ 986	$ (146)	10.43%	$ (1.1)		$ 667	$ 766	$ (99)	10.44%	$ (7.7)	
Cost of Capital	10.30%	10.43%	-0.13%	$ 840	(0.1)		10.29%	10.44%	-0.14%	$ 667	(0.7)	
Jurisdictional Factor	89.83%	90.27%	-0.45%	$ 840	-		89.18%	89.13%	0.04%	$ 667	-	
Other					0.9						5.8	
DSM:						**(1)** ◆						**4** ●
Program Expense (Revenue Net of Expense)	$ -	$ 0.1			$ (0.1)		$ 0.5	$ 0.4			$ 0.1	
Lost Sales	1.3	1.0			0.3		13.9	10.1			3.8	
Incentive	0.1	0.1			-		1.0	0.8			0.2	
Balancing Adjustment	(0.8)	-			(0.8)		0.1	-			0.1	
Net Fuel Recovery	$ 5.6	$ (0.6)				**6** ●	$ 7	$ (6)				**12** ●
Purchase Power Demand	(2.7)	(2.6)				**(0)** ◆	(23.9)	(25.2)				**1** ●
Transmission	0.4	0.4				**-** ●	7.9	8.2				**(0)** ◆
Other	(1.2)	(1.6)				**0** ●	(15.4)	(17.9)				**3** ●
Retail Margin Variance						**4** ●						**(44)** ◆
Off-System Margin Variance						**0** ●						**1** ●
Electric Margin Variance						**$ 4** ●						**$ (42)** ◆

(a) Non-Fuel Energy Analysis (net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 32	645,833	$ 48.79	$ 33	689,495	$ 48.46	$ (2) ◆	$ (2) ◆	$ 0 ●
Commercial	20	651,132	30.15	20	636,601	31.50	(1) ◆	1 ●	(1) ◆
Industrial	8	831,098	8.97	7	807,506	8.76	0 ●	0 ●	0 ●
Municipals	1	141,080	5.56	1	148,660	4.69	0 ●	- ●	0 ●
Other	6	251,137	23.27	5	231,818	23.00	1 ●	0 ●	0 ●
Native Load Total	**$ 65**	**2,520,280**	**$ 25.88**	**$ 67**	**2,514,081**	**$ 26.48**	**$ (1)** ◆	**$ (1)** ◆	**$ (0)** ◆

(a) Non-Fuel Energy Analysis (net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 429	8,821,968	$ 48.64	$ 445	9,162,977	$ 48.51	$ (15) ◆	$ (17) ◆	$ 1 ●
Commercial	206	6,572,769	31.30	218	6,791,244	32.06	(12) ◆	(7) ◆	(5) ◆
Industrial	71	8,147,788	8.74	73	8,239,869	8.85	(2) ◆	(1) ◆	(1) ◆
Municipals	8	1,570,795	5.04	8	1,627,769	4.69	0 ●	(0) ◆	1 ●
Other	52	2,375,436	21.88	56	2,430,998	23.15	(4) ◆	(1) ◆	(3) ◆
Native Load Total	**$ 766**	**27,488,757**	**$ 27.86**	**$ 799**	**28,252,857**	**$ 28.28**	**$ (33)** ◆	**$ (26)** ◆	**$ (7)** ◆

(b) Demand Analysis (net of base ECR revenue):

	MTD			YTD		
$mil	**Act**	**Bud**	**Variance**	**Act**	**Bud**	**Variance**
Commercial	13	13	(0)	134	148	(15)
Industrial	16	17	(1)	163	178	(15)
Municipals	4	4	(0)	41	44	(4)
Other	6	5	1	57	53	4
Native Load Total	**39**	**39**	**(1)**	**394**	**423**	**(29)**

Weather Statistics	MTD			YTD		
	Act	**+/- Bud**		**Act**	**+/- Bud**	
Heating Degree Days - Louisville	263	27	11%	3,007	134	5%
Heating Degree Days - Lexington	265	(13)	-5%	3,177	12	0%
Cooling Degree Days - Louisville	42	10	31%	1,446	(27)	-2%
Cooling Degree Days - Lexington	44	21	91%	1,244	56	5%

Gas Gross Margin — October 2013

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**$ -** 🟢	**$ 53**	**$ 50**		**$ 2** 🟢
Gas Supply Costs								
Gas Supply Costs	(8)	(7)	$ (2)		(114)	(104)	$ (10)	
GSC Revenue	8	7	2		114	105	9	
Net Gas Supply Costs				**0** 🟢				**$ (1)** ♦
Retail Gas (a)	**4**	**4**		**(0)** ♦	**63**	**61**		**$ 3** 🟢
Wholesale Gas (a)	**-**	**-**		**-** 🟢	**-**	**-**		**$ -** 🟢
DSM	**0**	**(0)**		**0** 🟢	**0**	**1**		**$ (0)** ♦
GLT	**0**	**1**		**(0)** ♦	**3**	**3**		**$ (0)** ♦
WNA	**(0)**	**-**		**(0)** ♦	**(2)**	**-**		**$ (2)** ♦
Other Margin	**0**	**0**		**(0)** ♦	**1**	**3**		**$ (2)** ♦
Gas Margin Variance				**$ (0)** ♦				**$ 1** ♦

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 3	996,025	$ 2.64	$ 3	967,407	$ 2.64	$ - ♦	$ 0 ♦	$ - 🟢
Commercial	-	465,916	-	1	470,930	2.06	(1) ♦	- 🟢	(1) ♦
Industrial	0	192,986	1.23	0	83,341	1.91	- 🟢	0 🟢	(0) ♦
Public Authority	0	68,935	1.74	0	87,545	1.93	(0) 🟢	- 🟢	- 🟢
Transportation	1	943,219	0.86	0	870,974	0.44	0 🟢	- 🟢	0 🟢
Ultimate Consumer	$ 4	2,667,081	$ 1.42	$ 4	2,480,197	$ 1.71	$ (0) ♦	$ 0 🟢	$ (1) ♦

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 39	14,832,558	$ 2.64	$ 39	14,951,175	$ 2.59	$ 0 🟢	$ (0) ♦	$ 1 🟢
Commercial	12	6,684,571	-	14	6,722,695	2.05	(2) ♦	- 🟢	(2) ♦
Industrial	2	1,226,038	1.49	1	743,442	1.86	0 🟢	1 🟢	(0) ♦
Public Authority	2	1,145,786	1.94	2	1,210,448	1.96	(0) ♦	(0) ♦	- 🟢
Transportation	8	9,574,641	0.85	4	9,058,335	0.44	4 🟢	0 🟢	4 🟢
Ultimate Consumer	$ 63	33,463,594	$ 1.54	$ 61	32,686,094	$ 1.84	$ 3 🟢	$ 1 🟢	$ 3 🟢

O&M **October 2013**

($ Millions)

	MTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 24	$ 20	$ (4)	$ -	$ 1	$ (4)	$ (4)	$ (0)	$ -	$ 4
Project Engineering	0	0	0	-	0	-	(0)	(0)	-	0
Transmission	2	2	0	-	0	-	0	0	-	0
Energy Supply and Analysis	1	1	0	-	0	-	0	0	-	(0)
Electric Distribution	5	6	0	-	0	-	(0)	0	(0)	0
Gas Distribution	2	3	1	-	0	-	0	0	(0)	0
Customer Services	8	8	(0)	-	0	-	(0)	0	(0)	0
Chief Operations Officer	**43**	**41**	**(3)**	**-**	**2**	**(4)**	**(4)**	**(0)**	**(0)**	**4**
Information Technology	4	5	1	-	1	-	0	(0)	-	0
General Counsel	2	3	1	-	0	-	0	(0)	-	0
Human Resources	1	1	0	-	0	-	0	0	-	0
Supply Chain	0	0	(0)	-	0	-	(0)	0	-	0
Chief Administrative Officer	**7**	**8**	**1**	**-**	**1**	**-**	**0**	**(0)**	**-**	**0**
Chief Financial Officer	**2**	**2**	**0**	**-**	**0**	**-**	**(0)**	**0**	**-**	**(0)**
Corporate	**10**	**12**	**2**	**1**	**(0)**	**-**	**1**	**0**	**-**	**0**
O&M Total MTD	**$ 62**	**$ 63**	**$ 1**	**$ 1**	**$ 2**	**$ (4)**	**$ (3)**	**$ (0)**	**$ (0)**	**$ 5**

	YTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 184	$ 190	$ 6	$ -	$ 6	$ 7	$ (1)	$ 2	$ -	$ (8)
Project Engineering	0	1	0	-	0	-	(0)	(0)	-	0
Transmission	24	25	1	-	(0)	-	1	0	-	0
Energy Supply and Analysis	7	9	2	-	1	-	0	0	(0)	1
Electric Distribution	58	58	1	-	(0)	-	(2)	3	(0)	0
Gas Distribution	25	28	4	-	1	-	3	0	-	0
Customer Services	68	77	9	-	(0)	-	-	-	-	9
Chief Operations Officer	**366**	**389**	**22**	**-**	**6**	**7**	**1**	**5**	**(0)**	**2**
Information Technology	39	42	3	-	3	-	(1)	(0)	-	1
General Counsel	23	28	5	-	0	-	4	(0)	-	0
Human Resources	5	6	1	-	0	-	0	0	-	0
Supply Chain	3	3	0	-	0	-	(0)	0	-	0
Chief Administrative Officer	**70**	**79**	**8**	**-**	**4**	**-**	**3**	**(0)**	**-**	**1**
Chief Financial Officer	**15**	**16**	**1**	**-**	**0**	**-**	**(0)**	**0**	**-**	**1**
Corporate	**119**	**121**	**2**	**(1)**	**(1)**	**-**	**3**	**1**	**1**	**(2)**
O&M Total YTD	**$ 570**	**$ 605**	**$ 35**	**$ (1)**	**$ 10**	**$ 7**	**$ 8**	**$ 6**	**$ 0**	**$ 3**

	Full Year			Variances						
	Forecast	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 220	$ 227	$ 7	$ -	$ 5	$ 3	$ 3	$ (3)	$ -	$ (1)
Project Engineering	1	1	0	-	0	-	(0)	(0)	-	0
Transmission	29	29	1	-	0	-	3	(3)	-	(0)
Energy Supply and Analysis	9	10	1	-	0	-	0	0	-	1
Electric Distribution	69	69	0	-	(1)	-	0	1	-	(0)
Gas Distribution	31	34	3	-	0	-	3	1	-	(0)
Customer Services	82	91	9	-	3	-	3	0	4	(1)
Chief Operations Officer	**440**	**461**	**21**	**-**	**9**	**3**	**12**	**(5)**	**4**	**(1)**
Information Technology	47	50	3	-	3	-	(1)	0	-	1
General Counsel	30	34	4	-	0	-	4	(0)	-	0
Human Resources	6	7	1	-	0	-	0	0	-	0
Supply Chain	3	3	0	-	0	-	0	-	-	0
Chief Administrative Officer	**87**	**95**	**8**	**-**	**3**	**-**	**4**	**0**	**-**	**2**
Chief Financial Officer	**17**	**19**	**2**	**-**	**0**	**-**	**0**	**-**	**-**	**2**
Corporate	**144**	**146**	**2**	**(1)**	**1**	**-**	**2**	**(0)**	**1**	**1**
O&M Total Full Year	**$ 688**	**$ 721**	**$ 35**	**$ (1)**	**$ 13**	**$ 3**	**$ 18**	**$ (5)**	**$ 4**	**$ 3**

Financing Activities October 2013

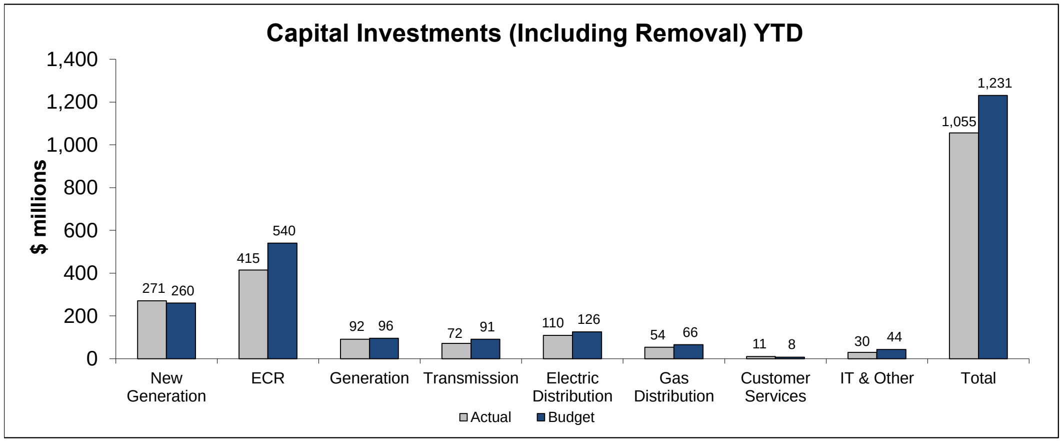
($ Millions)

	MTD			YTD			Full Year		
Balance Sheet	**Actual**	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**	**Forecast**	**Budget**	**Variance**
PCB									
Beg Bal	$ 931.8	$ 931.8	$ -	$ 932.0	$ 932.0	$ 0.0	$ 932.0	$ 932.0	$ -
End Bal	931.7	931.7	-	931.7	931.7	-	931.7	931.7	(0.0)
Ave Bal	**$ 931.7**	**$ 931.7**	**$ -**	**$ 931.9**	**$ 931.9**	**$ (0.0)**	**$ 931.8**	**$ 931.8**	**$ (0.0)**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 8.7**	**$ 11.4**	**$ 2.7**	**$ 10.6**	**$ 13.6**	**$ 3.0**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.11%**	**1.45%**	**0.34%**	**1.13%**	**1.46%**	**0.33%**
FMB/Sr Nts									
Beg Bal	$ 3,144.0	$ 3,144.0	$ (0.0)	$ 3,142.8	$ 3,142.8	$ 0.0	$ 3,142.8	$ 3,142.8	$ 0.0
End Bal	3,144.2	3,144.2	(0.0)	3,144.2	3,144.2	(0.0)	3,644.4	3,694.4	50.0
Ave Bal	**$ 3,144.1**	**$ 3,144.1**	**$ (0.0)**	**$ 3,143.5**	**$ 3,143.5**	**$ 0.1**	**$ 3,227.0**	**$ 3,235.3**	**$ 8.3**
Interest Exp	**$ 9.6**	**$ 9.6**	**$ (0.0)**	**$ 95.6**	**$ 95.6**	**$ (0.0)**	**$ 120.5**	**$ 120.2**	**$ (0.3)**
Rate	**0.00%**	**0.00%**	**0.00%**	**3.60%**	**3.60%**	**0.00%**	**3.73%**	**3.72%**	**-0.02%**
Short-term Debt									
Beg Bal	$ 263.7	$ 517.4	$ 253.7	$ 149.7	$ 149.7	$ (0.0)	$ 149.7	$ 149.7	$ (0.0)
End Bal	291.0	597.8	306.8	291.0	597.8	306.8	209.4	176.3	(33.1)
Ave Bal	**$ 277.3**	**$ 557.6**	**$ 280.3**	**$ 220.3**	**$ 393.7**	**$ 173.3**	**$ 290.1**	**$ 359.0**	**$ 69.0**
Interest Exp	**$ 0.2**	**$ 0.3**	**$ 0.1**	**$ 1,840.2**	**$ 2,037.3**	**$ 197.2**	**$ 2.4**	**$ 1.2**	**$ (1.2)**
Rate	**0.00%**	**0.00%**	**0.00%**	**0.99%**	**0.61%**	**-0.38%**			
Total End Bal	**$ 4,366.9**	**$ 4,673.7**	**$ 306.8**	**$ 4,366.9**	**$ 4,673.7**	**$ 306.8**	**$ 4,785.5**	**$ 4,802.4**	**$ 16.9**
Total Average Bal	**$ 4,353.2**	**$ 4,633.4**	**$ 280.3**	**$ 4,295.7**	**$ 4,469.1**	**$ 173.4**	**$ 4,448.9**	**$ 4,526.2**	**$ 77.3**
Total Expense Excl I/C	**$ 12.4**	**$ 12.6**	**$ 0.1**	**$ 123.6**	**$ 125.1**	**$ 1.5**	**$ 152.2**	**$ 153.8**	**$ 1.7**
Rate	**3.67%**	**3.49%**	**-0.18%**	**3.41%**	**3.32%**	**-0.09%**	**3.42%**	**3.40%**	**-0.02%**

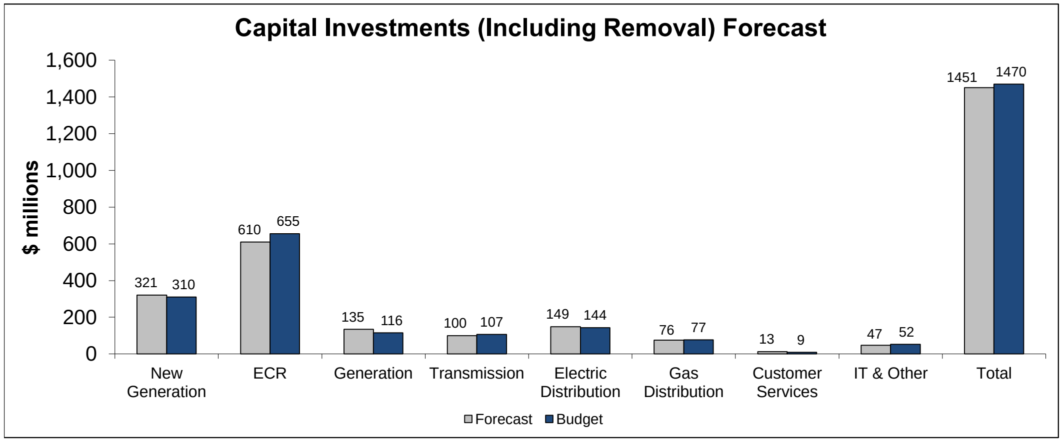
Balance Sheet October 2013

($ Millions)

	YTD	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 31	$ 10	$ 21	Primarily forward starting swaps settlement and issuance of revolver debt.
Accounts Receivable (Trade)	321	302	20	Due primarily to tariff rate variance in receivable logic and extended due date granted in rate case.
Inventory	291	270	21	Primarily an increase in fuel ($17m) and materials and supplies ($4m).
Deferred Income Taxes	20	13	6	
Prepayments and other current assets	40	64	(24)	Budget included $14m for forward hedging swaps entered into in Nov. 2012 compared to actuals of zero due to settlement in Sept.; also $5m for provision for bad debts above plan.
Total Current Assets	702	658	44	
Property, Plant, and Equipment	9,200	9,266	(67)	See capital chart for details.
Intangible Assets	229	229	1	
Other Property and Investments	1	1	1	
Regulatory Assets	594	620	(26)	Primarily interest rate swaps ($17m) and decrease in FAC ($17m).
Goodwill	997	997	-	
Other Long-term Assets	96	102	(6)	
Total Assets	**$ 11,820**	**$ 11,873**	**$ (53)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 366	$ 206	$ 160	Primarily differences in capex accrual and an increase in retainage fees and fuel volumes.
Accounts Payable - Affiliated Company	-	(0)	0	
Customer Deposits	49	48	1	
Derivative Liability	25	5	20	Primarily due to short-term derivative liability from forward hedges with PPL as counterparty ($14m).
Accrued Taxes	108	38	71	Timing of tax payments and accruals in actuals vs. budget.
Other Current Liabilities	175	154	21	Credit Cash Balance over plan ($15m); Accr Sal & Ben over plan ($6m)
Total Current Liabilities	723	451	272	
Debt - Affiliated Company	-	-	-	
Debt	4,367	4,674	(307)	Less short-term debt issued than budgeted ($282m) due to lower capital spend and notes payable to PPL ($25m). See Financing Activities page for more details.
Total Debt	4,367	4,674	(307)	
Deferred Tax Liabilities	652	690	(38)	Timing of recording of deferred taxes in actuals vs. budget.
Investment Tax Credit	135	134	1	
Accumulated Provision for Pension and Related Benefits	267	273	(6)	
Asset Retirement Obligation	246	131	115	ARO unplanned revaluation.
Regulatory Liabilities	1,043	987	56	Primarily due to short-term derivative asset gain from forward hedges entered into in Nov. 2012 and settled in Sept. 2013 with PPL as counterparty partially offset by loss from hedges entered into in Sept. 2013 with PPL as counterparty ($64m); offset by an increase in cost of removal ($8m).
Derivative Liability	38	54	(16)	Forward hedges with PPL as counterpary entered into in Sept. 2013.
Other Liabilities	254	236	19	Primarily long-term project engineering retention fee balances over Plan.
Total Deferred Credits and Other Liabilities	2,635	2,503	132	
Equity	4,094	4,245	(150)	
Total Liabilities and Equity	**$ 11,820**	**$ 11,873**	**$ (53)**	



Capital was $176m lower than budget YTD due mainly to timing delays to be largely made up in November and December – see Full Year Forecast below.



Capital is projected to be $19m lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.

Performance Report

November 2013

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Kentucky Regulated Dashboard

November 2013

Operational Metrics	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.27	0.89	1.36	1.36	N/A	1.35
Employee lost-time incidents	0	0	3	5	N/A	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,739	2,626	31,240	32,042	34,326	35,128
Utility EFOR	9.0%	5.1%	7.8%	5.1%	N/A	5.1%
Utility EAF	77.2%	83.1%	80.8%	86.6%	N/A	87.08%
Combined SAIFI	0.09	0.07	0.94	1.15	N/A	1.22
Combined SAIDI (minutes)	6.44	5.18	85.45	103.90	N/A	109.60
Steam Fleet Commercial Availability	92.5%	N/A	91.6%	91.3%	N/A	N/A
GwH Sales						
Residential	826	731	9,649	9,894	10,595	10,912
Commercial	589	613	7,161	7,404	7,792	8,063
Industrial	831	818	8,978	9,058	9,786	9,891
Municipals	145	153	1,716	1,780	1,878	1,944
Other	218	227	2,594	2,659	2,805	2,901
Off-System Sales	35	43	404	397	494	465
Total	2,643	2,586	30,502	31,193	33,349	34,175
Weather-Normalized Sales Growth			**TTM**			
Residential			0.73%			
Commercial			-0.77%			
Industrial			2.13%			
Other			-0.59%			
Total			0.59%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[1]	9.4%	6.6%	10.0%	9.5%	10.0%	9.6%
Electric Margins	$125	$122	$1,458	$1,497	$1,594	$1,638
Gas Margins	$17	$15	$139	$136	$160	$156

Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$27	$29	$298	$289	$321	$310
ECR	85	64	499	604	610	655
Generation	20	14	112	111	135	117
Transmission	12	8	84	99	100	107
Electric Distribution	18	10	129	136	149	144
Gas Distribution	7	6	62	72	76	77
Customer Services	1	1	12	9	13	9
IT and Other	3	3	33	47	47	51
Total	$173	$135	$1,229	$1,367	$1,451	$1,470

O&M ($ millions)[2]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$35	$39	$401	$428	$437	$461
Administrative	$6	7	$77	$86	85	95
Finance	$1	1	$16	$17	17	19
Burdens & Other Charges	$9	12	$128	$133	142	146
Total	$52	$59	$622	$664	$681	$721

Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,390	3,437	3,390	3,437	3,423	3,435

Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	3	0	14	10	N/A	14
NERC Possible Violations[3]	2	0	11	24	N/A	24

Variance Explanations

- The generation fleet's EAF and EFOR are unfavorable to budget due primarily to Mill Creek Unit 4 first reheater leaks, Mill Creek Unit 3 Turbine crossover expansion joint failure, Ghent Unit 4 cooling tower header failure, Trimble County Unit 2 low pressure turbine bearing failure and Cane Run Unit 4 generator rotor winding shorts. However, the units have run effectively when most needed as evidenced by the favorable YTD variance in Commercial Availability.
- Higher margins MTD on electric and gas due to volume increases resulting from colder than normal weather.
- Lower electric margins YTD due primarily to shortfalls of $59 million in electric energy and demand charge revenues, attributable to a mild summer, weak economic conditions (particularly the mining sector), as well as peak demand reductions and other changes in customer usage patterns. These shortfalls were partially offset by $23 million of incremental recovery on FAC (Fuel Adjustment Clause) and DSM (Demand Side Management) retail rate mechanisms.
- Lower O&M MTD primarily due to $3 million of lower outside services and $4 million of lower materials and other nonlabor costs.
- Lower O&M YTD primarily due to $13 million of labor savings, $9 million of lower outside services, $4 million of lower uncollectible accounts, $6 million of lower materials and $10 million of lower other nonlabor costs.
- Capital was $138m lower than budget YTD due mainly to timing delays to be largely made up in December – see Full Year Forecast below.
- Full year capital is projected to be $19 million lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.

Major Developments

- The Virginia Corporation Commission issued an order approving Old Dominion's settlement with no exceptions and an ROE range of 9.5% to 10.5% for annual information filings and earnings analysis. New rates, generating annual incremental revenues of $4.7 million, became effective December 1, 2013 consistent with the settlement.
- Nearly all the major construction contracts have been awarded with KU recently executing the engineering, procurement and construction ("EPC") contract with AMEC for the construction of the fabric filter on Brown Unit 3. EPC bids for Trimble County 1 are under evaluation and expected to be signed in January 2014.

Significant Future Events

- LG&E is expected to file a new permit for the Trimble County landfill in December after the Kentucky Division of Waste Management notified LG&E in May of its intent to deny the permit application. The new permit application will represent the next lowest cost alternate location which is also on existing plant property.
- LKE expects to make a filing with the Kentucky Public Service Commission at the end of December for a certificate for public convenience and necessity to build a new natural gas combined-cycle unit at the Green River site for commercial operation in 2018. The filing also proposes to construct about a 10-megawatt solar facility at its Brown generating station.

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(1) Excludes goodwill and other purchase accounting adjustments.

(2) Net of cost recovery mechanisms.

(3) The 11 NERC Possible Violation Issues for YTD Actual are expected to be resolved through NERC's Find, Fix and Track ("FFT") process without financial penalty.

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget and Forecast (Month) November 2013

($ Millions)

	MTD				MTD			
	Actual	**Budget**	**Variance**	**Comments**	**Actual**	**Q3 Forecast**	**Variance**	**Comments**
Revenues:								
Electric Revenues	$ 206	$ 205	$ 1		$ 206	$ 203	$ 3	
Gas Revenues	36	30	6	Due to increasing gas volumes resulting from colder than normal weather.	36	29	6	Due to increasing volumes resulting from colder than normal weather.
Total Revenues	242	235	7		242	232	9	
Cost of Sales:								
Fuel Electric Costs	68	68	(1)		68	67	(1)	
Gas Supply Expenses	19	16	(3)		19	15	(4)	
Purchased Power	5	6	1		5	4	(1)	
Other Electric Cost	8	10	2		8	9	1	
Total Cost of Sales	100	99	(1)		100	96	(5)	Due to increasing volumes resulting from colder than normal weather.
Gross Margin:								
Electric Margin	125	122	3		125	123	2	
Gas Margin	17	15	2		17	14	3	
Total Gross Margin	142	137	5	Due to increasing electric and gas volumes resulting from colder than normal weather.	142	137	5	Due to increasing electric and gas volumes resulting from colder than normal weather.
Operating Expenses:								
O&M	52	59	7	Primarily $3m of lower outside services and $4m of lower materials and other nonlabor costs identified as permanent savings.	52	59	7	Primarily $3m of lower outside services and $4m of lower materials and other nonlabor costs identified as permanent savings.
Depreciation & Amortization	28	28	1		28	28	0	
Taxes, Other than Income	4	4	0		4	4	0	
Total Operating Expenses	84	92	8		84	91	8	
Equity in earnings	-	(0)	0		-	-	-	
Other income	(0)	(0)	0		(0)	(0)	0	
EBIT	58	44	13		58	45	12	
Interest Expense	13	14	1		13	14	1	
Income from Ongoing Operations before income taxes	44	30	14		44	31	13	
Income Tax Expense	16	11	(6)	Higher pre-tax income.	16	11	(5)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**28**	**19**	**9**		**28**	**19**	**9**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	0	(0)	0		0	0	(0)	
Net Income (loss)	$ 28	$ 19	$ 9		$ 28	$ 19	$ 9	
KY Regulated Financing Costs	(3)	(3)	(0)		(3)	(3)	(0)	
KY Regulated Net Income	$ 25	$ 16	$ 9		$ 25	$ 17	$ 9	
Earnings Per Share	$ 0.04	$ 0.02	$ 0.01		$ 0.04	$ 0.02	$ 0.01	

Income Statement: Actual vs. Budget (YTD) November 2013

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,423	$ 2,514	$ (91)	Due to lower residential and commercial electric consumption volumes, lower demand charges and other customer/tariff mix changes partially offset by higher recoveries from fuel adjustment and demand side management rate mechanisms.
Gas Revenues	271	263	8	Due to increasing gas volumes resulting from colder than normal November weather.
Total Revenues	2,694	2,777	(83)	
Cost of Sales:				
Fuel Electric Costs	821	847	26	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.
Gas Supply Expenses	132	128	(4)	
Purchased Power	53	62	9	Lower purchases than originally planned.
Other Electric Cost	91	108	17	Lower electric volumes.
Total Cost of Sales	1,098	1,145	47	
Gross Margin:				
Electric Margin	1,458	1,497	(39)	See electric revenue comment above.
Gas Margin	139	136	3	
Total Gross Margin	1,597	1,633	(36)	
Operating Expenses:				
O&M	622	664	42	Primarily $13m of labor savings, $9m of lower outside services, $4m of lower uncollectible accounts, $6m of lower materials and $10m of lower other nonlabor costs.
Depreciation & Amortization	301	309	8	Delayed capital spend in 2012 and revised in-service dates for capital projects in 2013.
Taxes, Other than Income	43	44	1	
Total Operating Expenses	967	1,017	51	
Equity in earnings	-	(1)	1	
Other income	(7)	(8)	1	
EBIT	623	607	16	
Interest Expense	137	140	3	
Income from Ongoing Operations before income taxes	486	467	19	
Income Tax Expense	181	174	(6)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**305**	**293**	**12**	
Non Operating Income	1	-	1	
Discontinued Operations	2	(1)	3	
Net Income (loss)	$ 308	291	$ 16	
KY Regulated Financing Costs	(38)	(35)	(4)	
KY Regulated Net Income	$ 269	$ 257	$ 13	
Earnings Per Share	$ 0.42	$ 0.41	$ 0.01	

Income Statement: Forecast vs. Budget and Prior Forecast

November 2013

($ Millions)

	Full Year				Full Year			
	Forecast	**Budget**	**Variance**	**Comments**	**Forecast**	**Q3 Forecast**	**Variance**	**Comments**
Revenues:								
Electric Revenues	$ 2,654	$ 2,753	$ (99)	Due to lower residential and commercial electric consumption volumes, lower demand charges and other customer/tariff mix changes partially offset by higher recoveries from fuel adjustment and demand side management rate mechanisms.	$ 2,654	$ 2,650	$ 3	
Gas Revenues	320	313	7	Due to increasing gas volumes resulting from colder than normal November weather.	320	315	5	Due to increasing gas volumes resulting from colder than normal November weather.
Total Revenues	2,974	3,065	(92)		2,974	2,965	9	
Cost of Sales:								
Fuel Electric Costs	900	928	27		900	902	2	
Gas Supply Expenses	160	157	(3)		160	158	(3)	
Purchased Power	58	67	9		58	56	(2)	
Other Electric Cost	101	119	18		101	103	1	
Total Cost of Sales	1,220	1,271	51	Due to lower residential and commercial electric consumption volumes, lower demand charges and other customer/tariff mix changes partially offset by higher recoveries from fuel adjustment and demand side management rate mechanisms.	1,220	1,219	(1)	
Gross Margin:								
Electric Margin	1,594	1,638	(44)	Due to lower residential and commercial electric consumption volumes, lower demand charges and other customer/tariff mix changes partially offset by higher recoveries from fuel adjustment and demand side management rate mechanisms.	1,594	1,590	4	
Gas Margin	160	156	4		160	157	3	
Total Gross Margin	1,754	1,794	(40)		1,754	1,746	7	Due to increasing electric and gas volumes resulting from colder than normal weather.
Operating Expenses:								
O&M	681	721	40	Favorable labor and burdens, uncollectible accounts, outside services and materials.	681	693	12	Permanent cost savings identified in October and November.
Depreciation & Amortization	329	338	8	Revised estimates based on delayed capital spend in 2012 and revised in-service dates for capital projects in 2013.	329	330	0	
Taxes, Other than Income	47	48	1		47	48	1	
Total Operating Expenses	1,058	1,107	49		1,058	1,071	13	
Equity in earnings	-	(1)	1		-	-	-	
Other income	(8)	(8)	1		(8)	(8)	(0)	
EBIT	688	677	10		688	668	20	
Interest Expense	151	154	3		151	152	1	
Income from Ongoing Operations before income taxes	537	524	13		537	515	22	
Income Tax Expense	200	196	(4)		200	192	(8)	
Net Income (loss) from ongoing operations	**337**	**328**	**9**		**337**	**324**	**13**	
Non Operating Income	1	-	1		1	1	0	
Discontinued Operations	2	(1)	3		2	2	0	
Net Income (loss)	$ 340	$ 326	$ 13		$ 340	$ 326	$ 14	
KY Regulated Financing Costs	(41)	(37)	(4)		(41)	(41)	-	
KY Regulated Net Income	$ 299	$ 289	$ 9		$ 299	$ 285	$ 14	
Earnings Per Share	$ 0.46	$ 0.46	$ 0.00		$ 0.46	$ 0.46	$ -	

Electric Gross Margin — November 2013

($ Millions)

	MTD Actual	MTD Budget	MTD Unit Variance	MTD Value @	MTD Dollar Variance	MTD Margin Variance	YTD Actual	YTD Budget	YTD Unit Variance	YTD Value @	YTD Dollar Variance	YTD Margin Variance
Base Electric Margin:						$ 3 🟢						$ (57) ♦
Energy Volumes (a)	2,607,961	2,542,155	65,807	$ -	$ 4		30,096,719	30,795,012	(698,293)	$ -	$ (22)	
Energy Prices (a)					(1)						(8)	
Customer Charges (Avg. Customers)	938,902	948,354	(9,452)		0		935,889	945,701	(9,812)		2	
Demand Charges (b)	37	37			-		431	460			(29)	
ECR:						(0) ♦						(3) ♦
Average Rate Base	$ 904	$ 1,042	$ (138)	10.43%	$ (1.1)		$ 689	$ 791	$ (103)	10.43%	$ (8.7)	
Cost of Capital	10.32%	10.43%	-0.11%	$ 904	(0.1)		10.30%	10.43%	-0.14%	$ 689	(0.8)	
Jurisdictional Factor	88.21%	87.42%	0.79%	$ 904	0.1		89.06%	88.93%	0.13%	$ 689	0.1	
Other					0.8						6.6	
DSM:						(0) ♦						4 🟢
Program Expense (Revenue Net of Expense)	$ -	$ 0.1			$ (0.1)		$ 0.5	$ 0.5			$ -	
Lost Sales	1.1	1.0			0.1		14.9	11.1			3.8	
Incentive	0.1	0.1			-		1.1	0.9			0.2	
Balancing Adjustment	(0.2)	-			(0.2)		(0.1)	-			(0.1)	
Net Fuel Recovery	$ -	$ (0.5)				1 🟢	$ 7	$ (6)				13 🟢
Purchase Power Demand	(2.6)	(2.5)				(0) ♦	(26.6)	(27.7)				1 🟢
Transmission	0.8	0.8				- 🟢	8.7	9.0				(0) ♦
Other	(1.9)	(1.5)				(0) ♦	(17.3)	(19.4)				2 🟢
Retail Margin Variance						3 🟢						(40) ♦
Off-System Margin Variance						(0) ♦						1 🟢
Electric Margin Variance						$ 3 🟢						$ (39) ♦

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

MTD	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 40	825,624	$ 48.46	$ 35	730,835	$ 48.22	$ 5 🟢	$ 5 🟢	$ 0 🟢
Commercial	18	588,606	30.25	20	613,206	31.89	(2) ♦	(1) ♦	(1) ♦
Industrial	7	830,532	8.92	7	818,107	8.75	0 🟢	0 🟢	0 🟢
Municipals	1	144,996	5.56	1	152,611	4.69	0 🟢	- 🟢	0 🟢
Other	5	218,204	23.48	5	227,397	23.40	(0) ♦	(0) ♦	- 🟢
Native Load Total	**$ 71**	**2,607,961**	**$ 27.28**	**$ 68**	**2,542,155**	**$ 26.75**	**$ 3** 🟢	**$ 4** 🟢	**$ (1)** ♦

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

YTD	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 469	9,647,592	$ 48.62	$ 480	9,893,811	$ 48.49	$ (11) ♦	$ (12) ♦	$ 1 🟢
Commercial	224	7,161,375	31.21	237	7,404,450	32.04	(14) ♦	(8) ♦	(6) ♦
Industrial	79	8,978,320	8.76	80	9,057,976	8.84	(1) ♦	(1) ♦	(1) ♦
Municipals	9	1,715,791	5.09	8	1,780,380	4.69	0 🟢	(0) ♦	1 🟢
Other	57	2,593,640	22.01	62	2,658,395	23.17	(5) ♦	(2) ♦	(3) ♦
Native Load Total	**$ 837**	**30,096,719**	**$ 27.81**	**$ 867**	**30,795,012**	**$ 28.15**	**$ (30)** ♦	**$ (22)** ♦	**$ (8)** ♦

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD Variance
Commercial	12	12	0	146	160	(15)
Industrial	16	16	(1)	179	194	(15)
Municipals	4	4	(0)	44	48	(4)
Other	5	5	1	62	57	5
Native Load Total	**37**	**37**	**-**	**431**	**460**	**(29)**

Weather Statistics	MTD Act	MTD +/- Bud		YTD Act	YTD +/- Bud	
Heating Degree Days - Louisville	635	71	13%	3,642	205	6%
Heating Degree Days - Lexington	642	133	26%	3,819	145	4%
Cooling Degree Days - Louisville	0	(1)	-100%	1,446	(28)	-2%
Cooling Degree Days - Lexington	0	(2)	-100%	1,244	54	5%

Gas Gross Margin

November 2013

($ Millions)

	MTD					YTD				
	Actual	Budget	Subtotal	Margin Variance		Actual	Budget	Subtotal	Margin Variance	
Gas Base Service Charge	$ 5	$ 5		$ -	🟢	$ 58	$ 55		$ 2	🟢
Gas Supply Costs										
Gas Supply Costs	(19)	(15)	$ (4)			(133)	(119)	$ (14)		
GSC Revenue	19	15	4			133	120	13		
Net Gas Supply Costs				0	🟢				$ (1)	♦
Retail Gas (a)	11	8		3	🟢	74	68		$ 6	🟢
Wholesale Gas (a)	-	-		-	🟢	-	-		$ -	🟢
DSM	0	-		0	🟢	1	1		$ -	🟢
GLT	0	1		(1)	♦	3	3		$ (0)	♦
WNA	(0)	-		(0)	♦	(2)	-		$ (2)	♦
Other Margin	0	0		(0)	♦	1	3		$ (2)	♦
Gas Margin Variance				$ 2	🟢				$ 3	🟢

(a) Retail and wholesale gas sales - excludes GSC

	MTD											
	Actual			Budget			Variance					
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil		Volume $mil		Price $mil	
Residential	$ 7	2,641,453	$ 2.64	$ 5	2,035,701	$ 2.59	$ 2	🟢	$ 2	🟢	$ 0	🟢
Commercial	2	987,226	-	2	812,738	2.06	0	🟢	0	🟢	(0)	♦
Industrial	0	223,516	1.77	0	84,464	1.90	0	🟢	0	🟢	(0)	♦
Public Authority	0	183,563	2.16	0	176,406	2.00	-	🟢	-	🟢	-	🟢
Transportation	1	1,152,549	0.80	1	1,013,818	0.45	1	🟢	0	🟢	0	🟢
Ultimate Consumer	$ 11	5,188,307	$ 1.68	$ 8	4,123,127	$ 1.92	$ 3	🟢	$ 2	🟢	$ 0	🟢

	YTD											
	Actual			Budget			Variance					
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil		Volume $mil		Price $mil	
Residential	$ 46	17,474,011	$ 2.64	$ 44	16,986,875	$ 2.59	$ 2	🟢	$ 2	🟢	$ 0	🟢
Commercial	14	7,671,797	-	16	7,535,433	2.05	(1)	♦	0	🟢	(2)	♦
Industrial	2	1,449,554	1.53	2	827,907	1.86	1	🟢	0	🟢	0	♦
Public Authority	3	1,329,349	1.97	3	1,386,854	1.96	(0)	♦	-	♦	(0)	🟢
Transportation	9	10,727,190	0.85	4	10,072,152	0.44	5	🟢	0	🟢	5	🟢
Ultimate Consumer	$ 74	38,651,901	$ 1.56	$ 68	36,809,221	$ 1.85	$ 6	♦	$ 2	🟢	$ 3	♦

O&M November 2013

($ Millions)

	MTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 17	$ 21	$ 4	$ -	$ 0	$ 4	$ 3	$ 1	$ -	$ (4)
Project Engineering	0	0	0	-	0	-	(0)	(0)	-	0
Transmission	2	2	(0)	-	(0)	-	(0)	(0)	-	0
Energy Supply and Analysis	1	1	(0)	-	0	-	0	0	-	(0)
Electric Distribution	6	5	(1)	-	(0)	-	(1)	(0)	(0)	0
Gas Distribution	2	3	1	-	0	-	0	(0)	(0)	0
Customer Services	6	7	1	-	0	-	0	0	0	0
Chief Operations Officer	**35**	**39**	**4**	**-**	**0**	**4**	**3**	**1**	**0**	**(4)**
Information Technology	3	4	1	-	1	-	(0)	0	-	0
General Counsel	2	3	0	-	(0)	-	0	0	-	0
Human Resources	1	1	0	-	0	-	0	0	-	0
Supply Chain	0	0	0	-	0	-	0	0	-	0
Chief Administrative Officer	**6**	**7**	**1**	**-**	**1**	**-**	**0**	**0**	**-**	**0**
Chief Financial Officer	**1**	**1**	**0**	**-**	**0**	**-**	**0**	**0**	**-**	**0**
Corporate	**9**	**12**	**3**	**2**	**0**	**-**	**0**	**0**	**-**	**0**
O&M Total MTD	**$ 52**	**$ 59**	**$ 7**	**$ 2**	**$ 1**	**$ 4**	**$ 3**	**$ 1**	**$ 0**	**$ (3)**

	YTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 201	$ 211	$ 10	$ -	$ 6	$ 12	$ 1	$ 4	$ -	$ (12)
Project Engineering	0	1	0	-	0	-	(0)	(0)	-	0
Transmission	26	27	1	-	(0)	-	1	(0)	-	0
Energy Supply and Analysis	8	9	2	-	1	-	0	0	(0)	1
Electric Distribution	64	64	0	-	(0)	-	(3)	3	(0)	0
Gas Distribution	27	31	4	-	1	-	3	0	-	0
Customer Services	74	84	9	-	(0)	-	-	-	-	10
Chief Operations Officer	**401**	**428**	**27**	**-**	**6**	**12**	**4**	**6**	**(0)**	**(1)**
Information Technology	43	46	3	-	3	-	(1)	(0)	-	1
General Counsel	25	31	5	-	0	-	4	0	-	1
Human Resources	6	7	1	-	0	-	0	0	-	0
Supply Chain	3	3	0	-	0	-	0	0	-	0
Chief Administrative Officer	**77**	**86**	**10**	**-**	**4**	**-**	**4**	**(0)**	**-**	**2**
Chief Financial Officer	**16**	**17**	**2**	**-**	**1**	**-**	**(0)**	**0**	**-**	**1**
Corporate	**128**	**133**	**5**	**1**	**(0)**	**-**	**4**	**1**	**1**	**(2)**
O&M Total YTD	**$ 622**	**$ 664**	**$ 42**	**$ 1**	**$ 11**	**$ 12**	**$ 11**	**$ 8**	**$ 0**	**$ (1)**

	Full Year			Variances						
	Forecast	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 218	$ 227	$ 9	$ -	$ 6	$ 4	$ 4	$ (3)	$ -	$ (1)
Project Engineering	1	1	0	-	0	-	(0)	(0)	-	0
Transmission	29	29	0	-	0	-	3	(3)	-	(0)
Energy Supply and Analysis	9	10	1	-	0	-	0	0	-	0
Electric Distribution	69	69	0	-	(1)	-	0	1	-	(0)
Gas Distribution	30	34	4	-	0	-	3	1	-	(1)
Customer Services	82	91	9	-	3	-	3	0	4	(0)
Chief Operations Officer	**437**	**461**	**23**	**-**	**9**	**4**	**13**	**(4)**	**4**	**(2)**
Information Technology	47	50	4	-	3	-	(1)	0	-	1
General Counsel	29	34	6	-	0	-	5	(0)	-	2
Human Resources	6	7	1	-	0	-	0	0	-	0
Supply Chain	3	3	0	-	0	-	0	-	-	0
Chief Administrative Officer	**85**	**95**	**10**	**-**	**4**	**-**	**5**	**0**	**-**	**3**
Chief Financial Officer	**17**	**19**	**2**	**-**	**0**	**-**	**0**	**-**	**-**	**1**
Corporate	**142**	**146**	**4**	**2**	**0**	**-**	**2**	**(0)**	**1**	**(1)**
O&M Total Full Year	**$ 681**	**$ 721**	**$ 40**	**$ 2**	**$ 13**	**$ 4**	**$ 20**	**$ (4)**	**$ 4**	**$ 1**

Financing Activities November 2013

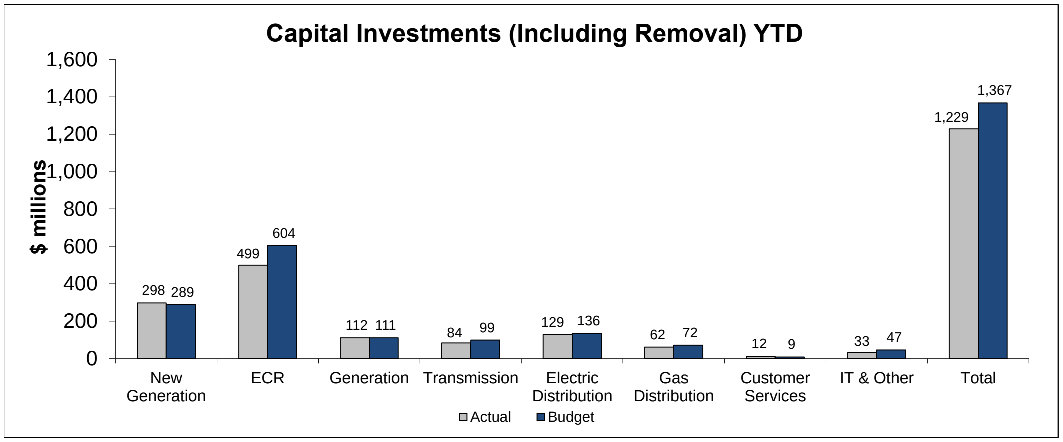
($ Millions)

	MTD			YTD			Full Year		
Balance Sheet	**Actual**	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**	**Forecast**	**Budget**	**Variance**
PCB									
Beg Bal	$ 931.7	$ 931.7	$ -	$ 932.0	$ 932.0	$ 0.0	$ 932.0	$ 932.0	$ -
End Bal	931.7	931.7	-	931.7	931.7	-	931.7	931.7	(0.0)
Ave Bal	**$ 931.7**	**$ 931.7**	**$ -**	**$ 931.9**	**$ 931.8**	**$ (0.0)**	**$ 931.8**	**$ 931.8**	**$ (0.0)**
Interest Exp	**$ 0.9**	**$ 1.1**	**$ 0.3**	**$ 9.6**	**$ 12.6**	**$ 3.0**	**$ 10.6**	**$ 13.6**	**$ 3.0**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.11%**	**1.45%**	**0.34%**	**1.13%**	**1.46%**	**0.33%**
FMB/Sr Nts									
Beg Bal	$ 3,144.2	$ 3,144.2	$ (0.0)	$ 3,142.8	$ 3,142.8	$ 0.0	$ 3,142.8	$ 3,142.8	$ 0.0
End Bal	3,640.7	3,694.3	53.6	3,640.7	3,694.3	53.6	3,644.4	3,694.4	50.0
Ave Bal	**$ 3,392.4**	**$ 3,419.2**	**$ 26.8**	**$ 3,391.7**	**$ 3,193.6**	**$ (198.1)**	**$ 3,227.0**	**$ 3,235.3**	**$ 8.3**
Interest Exp	**$ 10.6**	**$ 11.5**	**$ 0.9**	**$ 106.1**	**$ 107.1**	**$ 0.9**	**$ 120.5**	**$ 120.2**	**$ (0.3)**
Rate	**0.00%**	**0.00%**	**0.00%**	**3.37%**	**3.61%**	**0.24%**	**3.73%**	**3.72%**	**-0.02%**
Short-term Debt									
Beg Bal	$ 291.0	$ 597.8	$ 306.8	$ 149.7	$ 149.7	$ (0.0)	$ 149.7	$ 149.7	$ (0.0)
End Bal	75.0	196.1	121.1	75.0	196.1	121.1	209.4	176.3	(33.1)
Ave Bal	**$ 183.0**	**$ 396.9**	**$ 214.0**	**$ 112.3**	**$ 375.7**	**$ 263.4**	**$ 290.1**	**$ 359.0**	**$ 69.0**
Interest Exp	**$ 0.1**	**$ 0.2**	**$ 0.2**	**$ 1,997.2**	**$ 2,244.9**	**$ 247.7**	**$ 2.4**	**$ 1.2**	**$ (1.2)**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.92%**	**0.64%**	**-1.27%**			
Total End Bal	**$ 4,647.4**	**$ 4,822.1**	**$ 174.7**	**$ 4,647.4**	**$ 4,822.1**	**$ 174.7**	**$ 4,785.5**	**$ 4,802.4**	**$ 16.9**
Total Average Bal	**$ 4,507.1**	**$ 4,747.9**	**$ 240.8**	**$ 4,435.9**	**$ 4,501.1**	**$ 65.2**	**$ 4,448.9**	**$ 4,526.2**	**$ 77.3**
Total Expense Excl I/C	**$ 13.2**	**$ 14.5**	**$ 1.3**	**$ 136.8**	**$ 139.6**	**$ 2.8**	**$ 152.2**	**$ 153.8**	**$ 1.7**
Rate	**3.76%**	**3.92%**	**0.15%**	**3.32%**	**3.34%**	**0.02%**	**3.42%**	**3.40%**	**-0.02%**

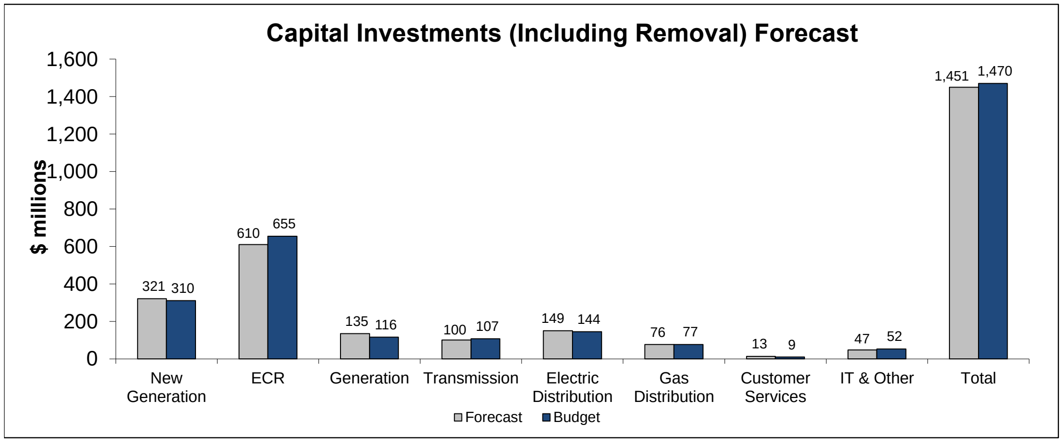
Balance Sheet November 2013

($ Millions)

	YTD	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 153	$ 10	$ 143	Primarily lower capex payments, lower dividends than budgeted, forward starting swaps settlement and issuance of revolver debt.
Accounts Receivable (Trade)	358	310	48	Due primarily to tariff rate variance in receivable logic and extended due date granted in rate case.
Inventory	295	273	23	Primarily an increase in fuel ($20m) and materials and supplies ($3m).
Deferred Income Taxes	20	13	6	
Prepayments and other current assets	39	62	(23)	Budget included ($14m) for forward hedging swaps entered into in Nov. 2012 compared to actuals of zero due to settlement in Sept.; ($6m) for provision for bad debts above plan; and ($2m) AR to PPL in plan but no actuals.
Total Current Assets	865	668	197	
Property, Plant, and Equipment	9,343	9,373	(30)	See capital chart for details.
Intangible Assets	225	224	1	
Other Property and Investments	1	1	1	
Regulatory Assets	588	614	(26)	Primarily interest rate swaps ($19m) and decrease in FAC ($10m).
Goodwill	997	997	-	
Other Long-term Assets	99	102	(3)	
Total Assets	**$ 12,118**	**$ 11,979**	**$ 139**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 409	$ 174	$ 235	Primarily differences in capex accrual and an increase in retainage fees and fuel volumes.
Accounts Payable - Affiliated Company	138	(0)	138	Dividend payable to PPL.
Customer Deposits	50	48	1	
Derivative Liability	4	5	(1)	
Accrued Taxes	120	39	81	Timing of tax payments and accruals in actuals vs. budget.
Other Current Liabilities	125	116	9	
Total Current Liabilities	845	383	462	
Debt - Affiliated Company	-	-	-	
Debt	4,647	4,822	(175)	Less long-term debt issued in November then budgeted ($54m); short-term debt less then plan ($96m) due to lower capital spend and notes payable to PPL ($25m). See Financing Activities page for more details.
Total Debt	4,647	4,822	(175)	
Deferred Tax Liabilities	652	697	(45)	Timing of recording of deferred taxes in actuals vs. budget.
Investment Tax Credit	135	134	1	
Accumulated Provision for Pension and Related Benefits	268	274	(6)	
Asset Retirement Obligation	247	131	115	ARO unplanned revaluation.
Regulatory Liabilities	1,046	985	61	Primarily due to short-term derivative asset gain from forward hedges entered into in Nov. 2012 and settled in Sept. 2013 with PPL as counterparty partially offset by loss from hedges entered into in Sept. 2013 with PPL as counterparty ($71m); offset by an increase in cost of removal ($8m).
Derivative Liability	36	54	(18)	Forward hedges with PPL as counterpary entered into in Sept. 2013.
Other Liabilities	258	236	22	Primarily long-term project engineering retention fee balances over Plan.
Total Deferred Credits and Other Liabilities	2,641	2,510	131	
Equity	3,984	4,263	(279)	
Total Liabilities and Equity	**$ 12,118**	**$ 11,979**	**$ 139**	



Capital was $138m lower than budget YTD due mainly to timing delays to be largely made up in December – see Full Year Forecast below.



Capital is projected to be $19m lower than budget due mainly to the portion of Trimble landfill delay not offset by other spend variances.

Performance Report

December 2013

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Kentucky Regulated Dashboard

December 2013

Operational Metrics	Current Month		YTD	
Safety	**Actual**	**PY**	**Actual**	**PY**
TCIR - Employees	0.43	1.26	1.29	1.35
Employee lost-time incidents	0	1	3	6
Reliability	**Actual**	**Budget**	**Actual**	**Budget**
Generation Volumes	3,099	3,086	34,338	35,128
Utility EFOR	6.4%	5.1%	7.7%	5.1%
Utility EAF	87.2%	92.3%	81.4%	87.1%
Combined SAIFI	0.10	0.07	1.04	1.22
Combined SAIDI (minutes)	9.64	5.71	95.09	109.60
Steam Fleet Commercial Availability	94.4%	N/A	91.9%	91.3%
GwH Sales				
Residential	1,114	1,018	10,761	10,912
Commercial	618	658	7,779	8,063
Industrial	755	833	9,733	9,891
Municipals	164	164	1,880	1,944
Other	221	242	2,815	2,901
Off-System Sales	97	68	503	465
Total	2,969	2,982	33,471	34,175
Weather-Normalized Sales Growth			**TTM**	
Residential			0.22%	
Commercial			-1.28%	
Industrial			1.52%	
Municipal			-0.78%	
Other			-1.73%	
Total			0.01%	

Variance Explanations

- The generation fleet's EAF and EFOR are unfavorable to budget due primarily to Mill Creek Unit 4 first reheater leaks and max steam flow issues, Mill Creek Unit 3 Turbine crossover expansion joint failure, Ghent Unit 4 cooling tower header failure, Trimble County Unit 2 low pressure turbine bearing failure and Cane Run Unit 4 generator rotor winding shorts. However, the units have run effectively when most needed as evidenced by the favorable YTD variance in Commercial Availability.

- Lower YTD margins due primarily to a shortfall of $58 million in electric energy revenues and demand charge revenues due to a mild summer, weak economic conditions (particularly the mining sector), as well as peak demand reductions and other changes in customer usage patterns. These shortfalls were partially offset by $15 million of net incremental recovery on rate mechanisms (FAC, DSM and ECR) and a combined $7 million of favorable margins from customer charges, gas deliveries and electric off system sales.

- Lower YTD O&M primarily due to $14 million of labor savings, $11 million of lower outside services, $7 million of lower materials, $5 million of lower uncollectible accounts, and $4 million of lower other nonlabor costs.

- Capital was $129m higher than budget MTD due primarily to increased spending on air compliance projects of $27 million, Ghent landfill of $27 million, Cane Run Unit 7 of $20 million and other timing variances from prior months that reversed in December.

- Capital was $11m lower than budget YTD due primarily to the portion of Trimble landfill delay not being offset by other spend variances.

	Current Month		YTD	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**
Utility ROE(1)	13.0%	11.5%	10.2%	9.6%
Electric Margins	$143	$142	$1,601	$1,638
Gas Margins	$20	$20	$159	$156
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**
New Generation	$44	$20	$343	$310
ECR	104	51	606	655
Generation	26	6	135	117
Transmission	12	8	95	107
Electric Distribution	22	9	150	144
Gas Distribution	10	5	71	77
Customer Services	3	0	14	9
IT and Other	11	4	45	51
Total	$232	$103	$1,459	$1,470
O&M ($ millions)(2)	**Actual**	**Budget**	**Actual**	**Budget**
Operations	$38	$34	$439	$461
Administrative	$8	9	$85	$95
Finance	$2	2	$18	$19
Burdens & Other Charges	$10	13	$138	$146
Total	$58	$57	$680	$721
Head Count	**Actual**	**Budget**	**Actual**	**Budget**
Full-time Employees	3,399	3,435	3,399	3,435
Other Metrics	**Actual**	**PY**	**Actual**	**PY**
Environmental Events	0	4	14	14
NERC Possible Violations(3)	0	0	11	24

Major Developments

- LKE continued advancement of its construction program in December as it executed an engineering, procurement and construction contract for the coal combustion residual transport system at its Brown facility. The Company also filed a new permit application for the landfill at Trimble County and a notice to file for its certificate of public convenience and necessity for its second combined cycle gas plant, Green River 5, and a proposed solar facility at Brown. For 2013, LKE prudently deployed $1.46 billion of capital, 40 percent more than any year in Company history, with a large portion of the investments earning real-time returns through ECR and other rate mechanisms.

- As a result of the recent “polar vortex”, LKE faced some of its coldest temperatures on record, leading to record-breaking energy usage across its service territories in the first part of January. The Company’s electric and gas systems performed well and successfully managed the increased energy demand while setting the following records: LG&E electric winter peak and natural gas 24-hour usage, KU all-time electric peak and all-time daily energy usage, and combined LG&E and KU electric winter peak and all-time daily energy usage. This solid start to 2014 follows a strong Q4 2013 where improved margins and continued cost management allowed LKE to beat earnings’ expectations.

- The Company will remain at the center of key energy and environmental policy debates as Kentucky lawmakers recently returned to Frankfort to begin the 2014 legislative session. In 2013, not only was there no significant state legislation that passed which adversely impacted LKE during 2013, but Company officials also provided testimony which was so compelling state representatives withdrew a bill which would have precluded the timely recovery of costs associated with natural gas used for electric generation.

Significant Future Events

- The Trimble County Fabric Filter EPC contract is currently under evaluation and is expected to be awarded in February.

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(1) Excludes goodwill and other purchase accounting adjustments.

(2) Net of cost recovery mechanisms.

(3) The 11 NERC Possible Violation Issues for YTD Actual are minor and likely to be resolved through NERC’s Find, Fix and Track (“FFT”) process without financial penalty.

Income Statement: Actual vs. Budget and Forecast (Month) December 2013

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 238	$ 239	$ (1)	
Gas Revenues	49	50	(1)	
Total Revenues	287	288	(1)	
Cost of Sales:				
Fuel Electric Costs	81	81	(0)	
Gas Supply Expenses	29	29	1	
Purchased Power	5	5	(0)	
Other Electric Cost	8	11	3	
Total Cost of Sales	123	126	3	
Gross Margin:				
Electric Margin	143	142	1	
Gas Margin	20	20	(0)	
Total Gross Margin	163	162	1	
Operating Expenses:				
O&M	58	57	(1)	
Depreciation & Amortization	28	29	1	
Taxes, Other than Income	4	4	0	
Total Operating Expenses	90	90	0	
Equity in earnings	-	(0)	0	
Other income	(1)	(1)	(0)	
EBIT	72	71	1	
Interest Expense	8	14	6	Favorable financing costs due to $5 million of net debt amortization adjustments associated with remarketed pollution-control bonds and $1 million of interest rate favorability.
Income from Ongoing Operations before income taxes	64	57	7	
Income Tax Expense	25	21	(3)	
Net Income (loss) from ongoing operations	**39**	**35**	**4**	
Non Operating Income	0	-	0	
Discontinued Operations	0	(0)	0	
Net Income (loss)	$ 40	$ 35	$ 4	
KY Regulated Financing Costs	(2)	(2)	0	
KY Regulated Net Income	$ 37	$ 33	$ 4	
Earnings Per Share	$ 0.06	$ 0.05	$ 0.01	

Income Statement: Actual vs. Budget (YTD) December 2013

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,661	$ 2,753	$ (91)	Due to lower residential and commercial electric consumption volumes, lower demand charges and other customer/tariff mix changes partially offset by higher recoveries from fuel adjustment and demand side management rate mechanisms.
Gas Revenues	320	313	7	Due to increasing gas volumes resulting from colder than normal November and December weather.
Total Revenues	2,981	3,065	(84)	
Cost of Sales:				
Fuel Electric Costs	902	928	26	Decreased electric volumes and prices. Offset by unfavorable electric revenues above.
Gas Supply Expenses	161	157	(4)	
Purchased Power	59	67	9	Lower purchases than originally planned.
Other Electric Cost	100	119	20	Lower electric volumes.
Total Cost of Sales	1,221	1,271	50	
Gross Margin:				
Electric Margin	1,601	1,638	(37)	Primarily to $58 million from electric energy and demand charge revenues due to a mild summer, weak economic conditions (particularly the mining sector), as well as peak demand reductions and other changes in customer usage patterns. These shortfalls were partially offset by $15 million of net incremental recovery on rate mechanisms (FAC, DSM and ECR) and a combined $4 million of favorable margins from customer charges and electric off system sales.
Gas Margin	159	156	3	
Total Gross Margin	1,760	1,794	(34)	
Operating Expenses:				
O&M	680	721	41	Primarily due to $14 million of labor savings, $11 million of lower outside services, $7 million of lower materials, $5 million of lower uncollectible accounts, and $4 million of lower other nonlabor costs.
Depreciation & Amortization	329	338	9	Delayed capital spend in 2012 and revised in-service dates for capital projects in 2013.
Taxes, Other than Income	47	48	1	
Total Operating Expenses	1,057	1,107	51	
Equity in earnings	-	(1)	1	
Other income	(8)	(8)	0	
EBIT	695	677	18	
Interest Expense	145	154	9	Favorable financing costs due to $5 million of net debt amortization adjustments associated with remarketed pollution-control bonds and $4 million of interest rate favorability and lower than budgeted debt levels.
Income from Ongoing Operations before income taxes	550	524	26	
Income Tax Expense	205	196	(10)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**345**	**328**	**17**	
Non Operating Income	1	-	1	
Discontinued Operations	2	(1)	3	
Net Income (loss)	$ 347	326	$ 21	
KY Regulated Financing Costs	(41)	(37)	(4)	
KY Regulated Net Income	$ 307	$ 289	$ 17	
Earnings Per Share	$ 0.48	$ 0.46	$ 0.02	

Electric Gross Margin December 2013

($ Millions)

	MTD Actual	MTD Budget	MTD Unit Variance	MTD Value @	MTD Dollar Variance	MTD Margin Variance	YTD Actual	YTD Budget	YTD Unit Variance	YTD Value @	YTD Dollar Variance	YTD Margin Variance
Base Electric Margin:						**$ 1** 🟢						**$ (56)** ♦
Energy Volumes (a)	2,872,091	2,914,279	(42,188)	$ -	$ 2		32,968,810	33,709,291	(740,481)	$ -	$ (20)	
Energy Prices (a)					1						(7)	
Customer Charges (Avg. Customers)	939,689	948,352	(8,663)		0		936,206	945,922	(9,716)		2	
Demand Charges (b)	37	39			(2)		468	499			(31)	
ECR:						**$ 2** 🟢						**(1)** ♦
Average Rate Base	$ 1,091	$ 1,085	$ 6	10.43%	$ -		$ 722	$ 816	$ (94)	10.43%	$ (8.7)	
Cost of Capital	10.41%	10.43%	-0.02%	$ 1,091	$ -		10.31%	10.43%	-0.12%	$ 722	(0.8)	
Jurisdictional Factor	87.30%	87.48%	-0.17%	$ 1,091	$ -		88.84%	88.77%	0.07%	$ 722	0.1	
Other					$ 1.6						8.2	
DSM:						**$ 0** 🟢						**4** 🟢
Program Expense (Revenue Net of Expense)	$ -	$ 0.1			$ (0.1)		$ 0.5	$ 0.5			$ -	
Lost Sales	1.2	1.0			$ 0.2		16.1	12.2			3.9	
Incentive	0.1	0.1			$ -		1.2	1.0			0.2	
Balancing Adjustment	0.4	-			$ 0.4		0.3	-			0.3	
Net Fuel Recovery	$ (2.5)	$ (0.5)				**$ (2)** ♦	$ 4	$ (7)				**11** 🟢
Purchase Power Demand	(2.9)	(2.6)				**$ (0)** ♦	(29.5)	(30.3)				**1** 🟢
Transmission	1.6	0.9				**$ 1** 🟢	10.3	9.9				**0** 🟢
Other	(1.9)	(1.3)				**$ (1)** ♦	(19.2)	(20.7)				**2** 🟢
Retail Margin Variance						**$ 1** 🟢						**(39)** ♦
Off-System Margin Variance						**$ 0** 🟢						**2** 🟢
Electric Margin Variance						**$ 1** 🟢						**$ (37)** ♦

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

MTD	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 54	1,113,900	$ 48.87	$ 49	1,017,827	$ 47.99	$ 6 🟢	$ 5 🟢	$ 1 🟢
Commercial	20	617,805	31.62	21	658,384	32.39	(2) ♦	(1) ♦	(1) ♦
Industrial	7	755,291	9.31	7	832,592	8.84	(0) ♦	(1) ♦	0 🟢
Municipals	1	164,229	5.56	1	163,566	4.69	0 🟢	- 🟢	0 🟢
Other	5	220,866	24.27	6	241,910	23.37	(0) ♦	(1) ♦	0 🟢
Native Load Total	**$ 87**	**2,872,091**	**$ 30.39**	**$ 84**	**2,914,279**	**$ 28.81**	**$ 3** 🟢	**$ 2** 🟢	**$ 1** 🟢

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

YTD	Actual Revenue $mil	Actual Volume (MWH)	Actual Price ($/MWH)	Budget Revenue $mil	Budget Volume (MWH)	Budget Price ($/MWH)	Variance Revenue $mil	Variance Volume $mil	Variance Price $mil
Residential	$ 524	10,761,493	$ 48.65	$ 529	10,911,638	$ 48.44	$ (5) ♦	$ (7) ♦	$ 2 🟢
Commercial	243	7,779,180	31.24	259	8,062,834	32.07	(16) ♦	(9) ♦	(6) ♦
Industrial	86	9,733,611	8.80	87	9,890,568	8.84	(2) ♦	(1) ♦	(0) ♦
Municipals	10	1,880,020	5.13	9	1,943,946	4.69	1 🟢	(0) ♦	1 🟢
Other	63	2,814,506	22.19	67	2,900,305	23.19	(5) ♦	(2) ♦	(3) ♦
Native Load Total	**$ 924**	**32,968,810**	**$ 28.04**	**$ 951**	**33,709,291**	**$ 28.21**	**$ (27)** ♦	**$ (20)** ♦	**$ (7)** ♦

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD Variance
Commercial	12	13	(1)	158	173	(15)
Industrial	16	17	(1)	194	211	(17)
Municipals	4	4	(0)	48	53	(4)
Other	5	5	0	67	62	5
Native Load Total	**37**	**39**	**(2)**	**468**	**499**	**(31)**

Weather Statistics	MTD Act	MTD +/- Bud		YTD Act	YTD +/- Bud	
Heating Degree Days - Louisville	840	24	3%	4,482	229	5%
Heating Degree Days - Lexington	831	(34)	-4%	4,650	111	2%
Cooling Degree Days - Louisville	0	(1)	-100%	1,446	(29)	-2%
Cooling Degree Days - Lexington	0	0	0%	1,244	54	5%

Gas Gross Margin December 2013

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**$ -** 🟢	**$ 63**	**$ 60**		**$ 2** 🟢
Gas Supply Costs								
Gas Supply Costs	(28)	(29)	$ 0		(161)	(148)	$ (14)	
GSC Revenue	29	28	1		162	148	14	
Net Gas Supply Costs				**1** 🟢				**$ 0** 🟢
Retail Gas (a)	**15**	**14**		**1** 🟢	**89**	**83**		**$ 6** 🟢
Wholesale Gas (a)	**-**	**-**		**-**	**-**	**-**		**$ -**
DSM	**0**	**(0)**		**1** 🟢	**1**	**0**		**$ 1** 🟢
GLT	**0**	**1**		**(1)** ♦	**4**	**4**		**$ (0)** ♦
WNA	**(2)**	**-**		**(2)** ♦	**(4)**	**-**		**$ (4)** ♦
Other Margin	**0**	**0**		**(0)** ♦	**1**	**3**		**$ (2)** ♦
Gas Margin Variance				**$ (0)** ♦				**$ 3** 🟢

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 10	3,627,524	$ 2.64	$ 10	3,849,705	$ 2.56	$ (0) ♦	$ (1) ♦	$ 0 🟢
Commercial	3	1,525,791	-	3	1,459,761	2.05	0 🟢	0 🟢	0 🟢
Industrial	0	210,134	1.73	0	102,552	1.88	0 🟢	0 🟢	- 🟢
Public Authority	1	287,307	2.08	1	270,959	2.00	0 🟢	- 🟢	- 🟢
Transportation	1	1,261,650	0.77	1	1,340,714	0.46	0 🟢	- 🟢	0 🟢
Ultimate Consumer	$ 15	6,912,406	$ 1.67	$ 14	7,023,691	$ 2.02	$ 1 🟢	$ (0) ♦	$ 1 🟢

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 56	21,101,535	$ 2.64	$ 54	20,836,580	$ 2.59	$ 2 🟢	$ 1 🟢	$ 1 🟢
Commercial	17	9,197,588	-	19	8,995,194	2.05	(1) ♦	0 🟢	(2) ♦
Industrial	3	1,659,688	1.56	2	930,459	1.87	1 🟢	1 🟢	(1) ♦
Public Authority	3	1,616,656	1.99	3	1,657,813	1.97	(0) ♦	(0) ♦	- 🟢
Transportation	10	11,988,840	0.84	5	11,412,866	0.44	5 🟢	0 🟢	5 🟢
Ultimate Consumer	$ 89	45,564,307	$ 1.57	$ 83	43,832,912	$ 1.88	$ 6 🟢	$ 3 🟢	$ 4 🟢

O&M **December 2013**

($ Millions)

	MTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 17	$ 16	$ (1)	$ -	$ (0)	$ (0)	$ (1)	$ (0)	$ -	$ 0
Project Engineering	$ 0	0	0	-	0	-	(0)	(0)	-	0
Transmission	$ 3	2	(1)	-	(0)	-	(1)	0	-	(0)
Energy Supply and Analysis	$ 1	1	(0)	-	(0)	-	0	0	-	0
Electric Distribution	$ 6	5	(1)	-	(0)	-	(1)	(0)	0	0
Gas Distribution	$ 3	3	(0)	-	(0)	-	0	(0)	(0)	(0)
Customer Services	$ 7	7	0	-	(0)	-	(0)	0	0	(0)
Chief Operations Officer	**38**	**34**	**(4)**	**-**	**(2)**	**(0)**	**(2)**	**(1)**	**0**	**0**
Information Technology	4	5	0	-	0	-	0	0	-	(0)
General Counsel	3	4	0	-	(0)	-	1	0	-	(0)
Human Resources	1	1	(0)	-	(0)	-	(0)	0	-	(0)
Supply Chain	0	0	(0)	-	(0)	-	(0)	(0)	-	0
Chief Administrative Officer	**8**	**9**	**0**	**-**	**(0)**	**-**	**1**	**0**	**-**	**(0)**
Chief Financial Officer	**2**	**2**	**(0)**	**-**	**(0)**	**-**	**(0)**	**0**	**-**	**0**
Corporate	**10**	**13**	**3**	**2**	**1**	**-**	**0**	**0**	**1**	**(1)**
O&M Total MTD	**$ 58**	**$ 57**	**$ (1)**	**$ 2**	**$ (1)**	**$ (0)**	**$ (1)**	**$ (0)**	**$ 1**	**$ (1)**

	YTD			Variances						
	Actual	Budget	Total Variance	Overhead	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 219	$ 227	$ 8	$ -	$ 5	$ 2	$ 0	$ 3	$ -	$ (2)
Project Engineering	1	1	0	-	0	-	(0)	(0)	-	0
Transmission	29	29	0	-	(1)	-	1	(0)	-	0
Energy Supply and Analysis	9	10	2	-	0	-	0	0	(0)	1
Electric Distribution	70	69	(1)	-	(2)	-	(3)	3	(0)	2
Gas Distribution	30	34	4	-	1	-	3	(0)	(0)	(0)
Customer Services	82	91	9	-	3	-	1	0	4	1
Chief Operations Officer	**439**	**461**	**22**	**-**	**6**	**2**	**3**	**6**	**4**	**2**
Information Technology	47	50	4	-	4	-	(1)	(0)	-	1
General Counsel	29	34	6	-	0	-	5	0	-	0
Human Resources	7	7	1	-	0	-	0	0	-	0
Supply Chain	3	3	0	-	0	-	0	0	-	0
Chief Administrative Officer	**85**	**95**	**10**	**-**	**4**	**-**	**5**	**0**	**-**	**2**
Chief Financial Officer	**18**	**19**	**1**	**-**	**0**	**-**	**(0)**	**0**	**-**	**1**
Corporate	**138**	**146**	**8**	**3**	**1**	**-**	**4**	**1**	**1**	**(3)**
O&M Total YTD	**$ 680**	**$ 721**	**$ 41**	**$ 3**	**$ 11**	**$ 2**	**$ 11**	**$ 7**	**$ 5**	**$ 2**

Financing Activities

December 2013

($ Millions)

	MTD			YTD		
Balance Sheet	**Actual**	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**
PCB						
Beg Bal	$ 931.7	$ 931.7	$ -	$ 932.0	$ 932.0	$ 0.0
End Bal	924.0	931.7	7.7	924.0	931.7	7.7
Ave Bal	**$ 927.8**	**$ 931.7**	**$ 3.8**	**$ 928.0**	**$ 931.8**	**$ 3.8**
Interest Exp	**$ (6.9)**	**$ 1.0**	**$ 8.0**	**$ 2.7**	**$ 13.6**	**$ 10.9**
Rate	**-0.01%**	**0.00%**	**0.01%**	**0.28%**	**1.44%**	**1.16%**
FMB/Sr Nts						
Beg Bal	$ 3,640.7	$ 3,694.3	$ 53.6	$ 3,142.8	$ 3,142.8	$ 0.0
End Bal	3,640.9	3,694.4	53.6	3,640.9	3,694.4	53.6
Ave Bal	**$ 3,640.8**	**$ 3,694.4**	**$ 53.6**	**$ 3,391.8**	**$ 3,235.3**	**$ (156.5)**
Interest Exp	**$ 11.5**	**$ 11.5**	**$ 0.0**	**$ 117.6**	**$ 118.6**	**$ 0.9**
Rate	**0.00%**	**0.00%**	**0.00%**	**3.42%**	**3.61%**	**0.19%**
Short-term Debt						
Beg Bal	$ 75.0	$ 196.1	$ 121.1	$ 149.7	$ 149.7	$ (0.0)
End Bal	245.0	176.3	(68.7)	245.0	176.3	(68.7)
Ave Bal	**$ 160.0**	**$ 186.2**	**$ 26.2**	**$ 197.3**	**$ 359.1**	**$ 161.8**
Interest Exp	**$ 0.0**	**$ 0.1**	**$ 0.1**	**$ 2,154.3**	**$ 2,362.4**	**$ 208.1**
Rate	**0.00%**	**0.00%**	**0.00%**	**1.08%**	**0.65%**	**-0.43%**
Total End Bal	**$ 4,809.8**	**$ 4,802.4**	**$ (7.4)**	**$ 4,809.8**	**$ 4,802.4**	**$ (7.4)**
Total Average Bal	**$ 4,728.6**	**$ 4,812.2**	**$ 83.6**	**$ 4,517.1**	**$ 4,526.3**	**$ 9.1**
Total Expense Excl I/C	**$ 8.2**	**$ 14.3**	**$ 6.0**	**$ 145.0**	**$ 153.8**	**$ 8.8**
Rate	**2.24%**	**3.82%**	**1.58%**	**3.17%**	**3.35%**	**0.19%**

Credit Facilities ($ Millions)	**Committed Capacity**	**Borrowed**	**Letters of Credit Issued**	**Unused Capacity**
LKE	$ 300	$ 75		$ 225
LG&E	500	20		480
KU	598	150	$ 198	250
TOTAL	$ 1,398	$ 245	$ 198	$ 955

Credit Metrics ($ Millions)	**YTD Actual**	**YTD +/- Bud**
FFO to Debt - LG&E	28.8%	+0.02
FFO to Debt - KU	24.3%	-0.02
Debt to EBITDA - LG&E (1)	3.14	-0.17
Debt to EBITDA - KU (1)	3.66	+0.00
Debt to Capitalization - LG&E (2)	46.7%	+0.01
Debt to Capitalization - KU (2)	47.9%	+0.01

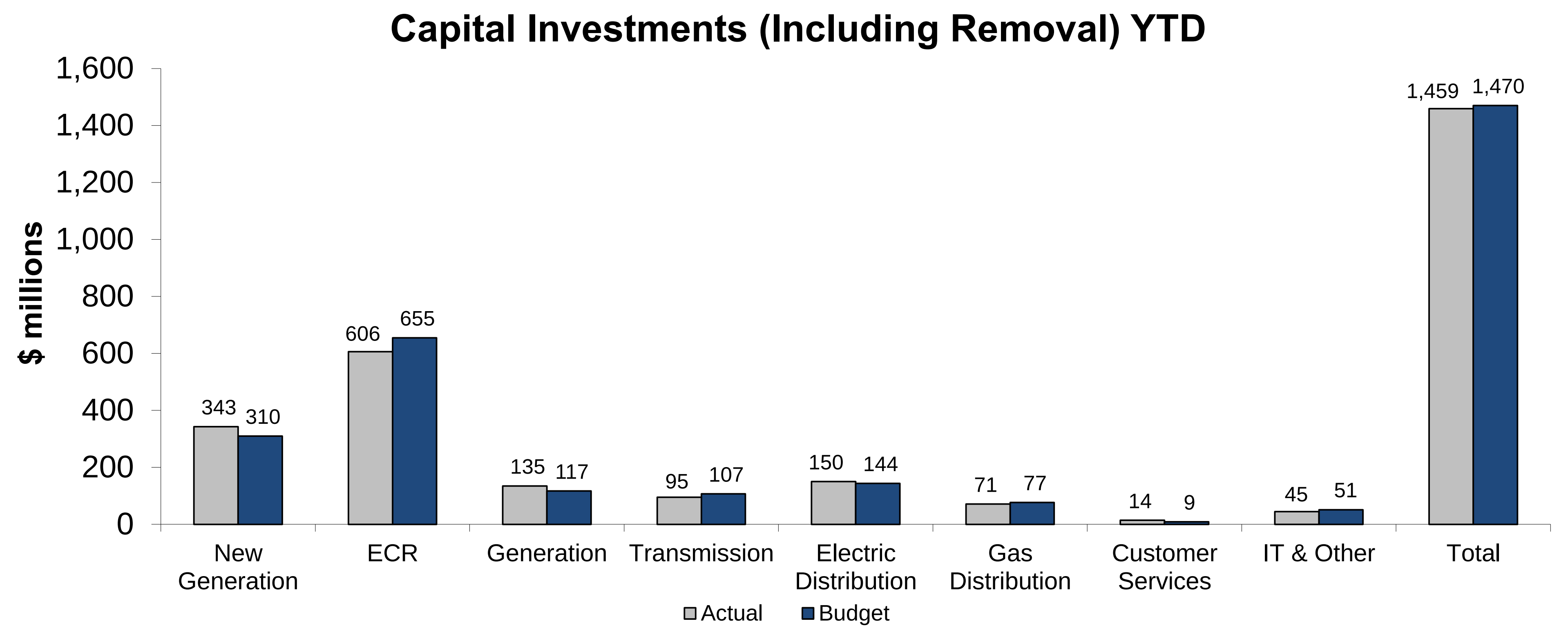
(1) Actuals represent a trailing 12 months

(2) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet December 2013

($ Millions)

	YTD	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 35	$ 10	$ 25	See Cash Flow Statement explanations.
Accounts Receivable (Trade)	410	328	82	Due primarily to tariff rate variance in receivable logic and extended due date granted in rate case.
Inventory	278	260	19	Primarily an increase in fuel ($13m) and materials and supplies ($4m).
Deferred Income Taxes	159	13	146	Due to the reclassification of deferred taxes from non-current to current for expected 2014 use of our net operating loss carry forwards.
Prepayments and other current assets	108	60	47	Unbudgeted notes received from assoc company $70m offset by budget including ($14m) for forward hedging swaps entered into in Nov. 2012 compared to actuals of zero due to settlement in Sept., ($4m) for provision for bad debts above plan, and ($2m) AR to PPL in plan but no actuals.
Total Current Assets	990	671	319	
Property, Plant, and Equipment	9,544	9,449	95	Primarily due to ARO unplanned revaluation ($113m). AROs were revalued primarily due to updates in the estimated cash flows for ash ponds and CCR surface impoundments based on updated cost estimates. This was partially offset by CapEx YTD variance ($11m) (see capital chart for details).
Intangible Assets	221	220	0	
Other Property and Investments	1	1	1	
Regulatory Assets	502	612	(110)	Primarily Pension and Postretirement due to increases in the discount rate ($77m) and interest rate swaps ($23m).
Goodwill	997	997	-	
Other Long-term Assets	96	102	(5)	
Total Assets	**$ 12,350**	**$ 12,051**	**$ 299**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 349	$ 181	$ 168	Primarily differences in CapEx accrual ($22m) and an increase in retainage fees ($22m) and fuel volumes ($35m).
Accounts Payable - Affiliated Company	(0)	(0)	0	
Customer Deposits	50	48	1	
Derivative Liability	4	5	(1)	
Accrued Taxes	39	26	13	Timing of tax payments and accruals in actuals vs. budget.
Other Current Liabilities	136	128	8	
Total Current Liabilities	578	389	189	
Debt - Affiliated Company	-	-	-	
Debt	4,810	4,802	7	
Total Debt	4,810	4,802	7	
Deferred Tax Liabilities	965	727	238	See Deferred Income Taxes explanation above. Remaining difference due to an increase to current year NOL utilization ($153m). This was partially offset by a decrease in bonus depreciation ($63m).
Investment Tax Credit	135	133	1	
Accumulated Provision for Pension and Related Benefits	152	274	(122)	Due to an increase in the discount rate.
Asset Retirement Obligation	245	132	113	ARO unplanned revaluation due to updates in the estimated cash flows for ash ponds and CCR surface impoundments based on updated cost estimates.
Regulatory Liabilities	1,047	983	64	Primarily due to short-term derivative asset gain from forward hedges entered into in Nov. 2012 and settled in Sept. 2013 with PPL as counterparty partially offset by loss from hedges entered into in Sept. 2013 with PPL as counterparty ($70m); offset by an increase in cost of removal ($15m).
Derivative Liability	32	54	(21)	Forward hedges with PPL as counterparty entered into in Sept. 2013.
Other Liabilities	238	231	7	
Total Deferred Credits and Other Liabilities	2,814	2,533	281	
Equity	4,149	4,328	(178)	
Total Liabilities and Equity	**$ 12,350**	**$ 12,051**	**$ 299**	


Capital Investments (Including Removal) YTD
$ millions
1,600
1,400
1,200
1,000
800
600
400
200
0
343
310
606
655
135
117
95
107
150
144
71
77
14
9
45
51
1,459
1,470
New Generation
ECR
Generation
Transmission
Electric Distribution
Gas Distribution
Customer Services
IT & Other
Total
Actual
Budget

Cash Flow

December 2013

YTD	Actual	Budget	Variance	Comments
Net income	347	326	21	Favorable O&M partially offset by lower margins due to a mild summer, weak economic conditions (particularly the mining sector), as well as peak demand reductions and other changes in customer usage patterns. (See Income Statement).
Depreciation	355	356	-1	
Deferred tax expense	254	178	75	Primarily due to an increase to current year NOL utilization, partially offset by a decrease in bonus depreciation. (see Balance Sheet)
Other Balance Sheet Movements	8	8	0	
Funds From Operations	**965**	**869**	**96**	
Changes in accounts receivables	-117	-35	-82	Due primarily to tariff rate variance in receivable logic and extended due date granted in rate case.
Changes in inventories	-2	15	-18	Primarily an increase in fuel and materials and supplies.
Changes in accounts payable	65	-100	165	Primarily differences in CapEx accrual and an increase in retainage fees and fuel volumes.
Change in Working Capital	**-54**	**-119**	**65**	
Operating Cash flow	**911**	**750**	**161**	
Capex	-1,434	-1,576	142	Primarily due to ARO unplanned revaluation.
Other Investing	-59	0	-59	Net decrease in notes receivable from affiliates.
Loans to Affiliates	0	0	0	
Investing Cash flow	**-1,493**	**-1,576**	**83**	
Dividends	-254	-157	-97	Higher dividends and lower equity infusions due to lower than expected CapEx spend, the tax NOL settlement being higher than budgeted, and the cash received from swap settlements being higher than budgeted.
Equity Infusion	243	374	-131	
Net Borrowings	591	577	14	Due to refinancing a LKE revolving credit line with PPL and entering into a "community debt" credit line while borrowing against the whole amount.
Other	-6	0	-6	
Financing Cash flow	**574**	**793**	**-219**	
Net increase (decrease) in cash	**-8**	**-33**	**24**	

Performance Report

January 2014

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Kentucky Regulated Dashboard

January 2014

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.59	2.92	1.59	2.92	1.59	1.29
Employee lost-time incidents	0	0	0	0	0	3
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,386	3,218	3,386	3,218	34,803	34,635
Utility EFOR	3.3%	5.9%	3.3%	5.9%	N/A	5.9%
Utility EAF	93.6%	92.3%	93.6%	92.3%	N/A	82.5%
Steam Fleet Commercial Availability	99.0%	91.5%	99.0%	91.5%	N/A	91.5%
Combined SAIFI	0.12	0.07	0.12	0.07	N/A	1.20
Combined SAIDI (minutes)	9.64	5.75	9.64	5.75	N/A	107.60
GwH Sales						
Residential	1,418	1,114	1,418	1,114	10,962	10,962
Commercial	743	667	743	667	7,952	7,952
Industrial	815	817	815	817	10,011	10,011
Municipals	194	170	194	170	1,969	1,969
Other	260	236	260	236	2,788	2,788
Off-System Sales	88	83	88	83	273	273
Total	3,517	3,088	3,517	3,088	33,954	33,954
Weather-Normalized Sales Growth			**TTM**			
Residential			-0.48%			
Commercial			-0.54%			
Industrial			1.51%			
Municipal			-1.02%			
Other			0.27%			
Total			0.12%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE(1)	17.8%	12.7%	17.8%	12.7%	9.1%	8.7%
Electric Margins	$168	$145	$168	$145	$1,664	$1,664
Gas Margins	26	22	26	22	157	157
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$14	$21	$14	$21	$114	$126
ECR	36	34	36	34	618	603
Generation	2	6	2	6	119	122
Transmission	6	7	6	7	81	77
Electric Distribution	9	9	9	9	147	143
Gas Distribution	4	5	4	5	80	80
Customer Services	0	1	0	1	18	20
IT and Other	1	4	1	4	52	50
Total	$72	$87	$72	$87	$1,229	$1,221
O&M ($ millions)(2)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$36	$33	$36	$33	$468	$468
Administrative	7	8	7	8	98	98
Finance	2	2	2	2	19	19
Burdens & Other Charges	11	12	11	12	150	150
Total	$55	$55	$55	$55	$735	$735
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,407	3,524	3,407	3,524	3,549	3,549
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	1	1	1	1	N/A	14
NERC Possible Violations	0	0	0	0	N/A	11

Variance Explanations

- Generation volumes and GWh sales were impacted by cold weather in January. Generation volumes were also impacted by excellent plant availability.

- Higher electric margins were primarily due to $19 million from retail volumes impacted by weather and $4 million from excess generation sold at market prices.

Major Developments

- LKE demonstrated another solid safety performance in 2013, earning multiple safety and wellness awards. LG&E and KU's recordable rate for the year of 1.29 falls below last year's rate of 1.35 and the National Safety Council utility average of 3.10. Contractor metrics for the year were also strong with a recordable rate of 1.26 compared to 1.39 in 2012.

- The month of January brought the "polar vortex" and several days of colder than normal temperatures, snow and ice accumulation to our Kentucky service territories. LG&E and KU's electric and gas systems performed extremely well during this period. Commercial availability for the generation fleet was 99%, with no outages during the coldest days of the month. In addition to shattering numerous peak and usage records, the following statistics were also established for the LG&E and KU service territories during January 2014:
    - Third highest electricity delivery month in LG&E and KU's history, just behind August 2007 and August 2010
    - Seven days in January 2014 are included in the top 10 all-time electricity delivery days
    - Combined load exceeded the 6,000 MW level for 99 hours, whereas the 6,000 MW level had not been reached since February 2011

Major Developments (CONT'D)

- Moody's recently upgraded several ratings for LG&E and KU. Each company's issuer and senior unsecured ratings were upgraded to A3 from Baa1 and their senior secured ratings were upgraded to A1 from A2.

Significant Future Events

- The Trimble Country Fabric Filter Engineering, Procurement and Construction contract is currently under evaluation and is expected to be awarded during the first quarter.

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(1) Excludes goodwill and other purchase accounting adjustments.

(2) Net of cost recovery mechanisms.

Income Statement: Actual vs. Budget and Forecast (Month/Year) January 2014

($ Millions)

	MTD/YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 290	$ 243	$ 47	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Revenues	71	54	16	Due to increasing gas volumes resulting from colder than normal weather.
Total Revenues	360	297	63	
Cost of Sales:				
Fuel Electric Costs	108	84	(24)	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Supply Expenses	44	32	(13)	Due to increasing gas volumes resulting from colder than normal weather.
Purchased Power	5	5	(0)	
Other Electric Cost	9	9	1	
Total Cost of Sales	166	130	(36)	
Gross Margin:				
Electric Margin	168	145	23	Higher margins primarily due to $19 million from retail electric volumes impacted by favorable weather and $4 million from excess generation sold at market prices.
Gas Margin	26	22	4	
Total Gross Margin	194	167	27	
Operating Expenses:				
O&M	55	55	(0)	
Depreciation & Amortization	28	28	0	
Taxes, Other than Income	4	4	(0)	
Total Operating Expenses	88	88	0	
Other income	(1)	(1)	0	
EBIT	106	78	28	
Interest Expense	14	14	0	
Income from Ongoing Operations before income taxes	92	63	28	
Income Tax Expense	34	24	(10)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**$ 57**	**$ 39**	**$ 18**	
Non Operating Income	0	0	0	
Discontinued Operations	0	0	(0)	
Net Income (loss)	$ 57	$ 39	$ 18	
KY Regulated Financing Costs	(3)	(3)	(0)	
KY Regulated Net Income	$ 55	$ 37	$ 18	
Earnings Per Share	$ 0.08	$ 0.05	$ 0.03	

Electric Gross Margin January 2014

($ Millions)

	MTD/YTD					
	Actual	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**
Base Electric Margin:						● $ 18
Energy Volumes (a)	3,429,237	3,004,617	424,620	$ -	$ 18	
Energy Prices (a)					(2)	
Customer Charges (Avg. Customers)	940,681	944,712	(4,031)		(0)	
Demand Charges (b)	39	37			2	
ECR:						◆ $ (1)
Average Rate Base	$ 1,126	$ 1,113	$ 14	10.42%	$ 0.1	
Cost of Capital	10.21%	10.42%	-0.21%	$ 1,126	$ (0.2)	
Jurisdictional Factor	83.33%	86.22%	-2.89%	$ 1,126	$ (0.3)	
Other					$ (0.6)	
DSM:						● $ -
Program Expense (Revenue Net of Expense)	$ -	$ -			$ -	
Lost Sales	1.2	1.9			$ (0.7)	
Incentive	0.1	0.1			$ -	
Balancing Adjustment	0.7	-			$ 0.7	
Net Fuel Recovery	$ (2.0)	$ (0.4)				◆ $ (2)
Purchase Power Demand	(1.5)	(2.6)				● $ 1
Transmission	1.5	1.1				● $ 1
Other	(2.2)	(4.1)				● $ 2
Retail Margin Variance						● $ 19
Off-System Margin Variance						● $ 4
Electric Margin Variance						● $ 23

(a) Non-Fuel Energy Analysis (net of base ECR revenue):

	MTD/YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 68	1,418,207	$ 48.23	$ 54	1,113,850	$ 48.52	● $14	● $15	◆ ($0)
Commercial	24	743,113	31.60	22	667,295	33.00	● $2	● $3	◆ ($1)
Industrial	7	814,624	8.99	7	816,989	8.98	● $0	● $0	● $0
Municipals	1	193,580	5.56	1	170,221	5.56	● $0	● $0	● $0
Other	6	259,713	23.78	6	236,262	23.86	● $1	● $1	● $0
Native Load Total	**$ 107**	**3,429,237**	**$ 31.05**	**$ 90**	**3,004,617**	**$ 29.95**	● **$17**	● **$18**	◆ **($2)**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD/YTD		
	Act	Bud	Variance
Commercial	13	12	2
Industrial	16	16	(0)
Municipals	5	5	1
Other	5	5	0
Native Load Total	**39**	**37**	**2**

Gas Gross Margin January 2014

($ Millions)

	MTD/YTD			
	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		● **$ -**
Gas Supply Costs				
Gas Supply Costs	(44)	(32)	$ (12)	
GSC Revenue	44	31	13	
Net Gas Supply Costs				● **$ 1**
Retail Gas (a)	**21**	**16**		● **$ 5**
Wholesale Gas (a)	**(0)**	**-**		◆ **$ (1)**
DSM	**0**	**0**		● **$ 0**
GLT	**0**	**1**		◆ **$ (0)**
WNA	**(1)**	**-**		◆ **$ (1)**
Other Margin	**0**	**0**		● **$ 0**
Gas Margin Variance				● **$ 4**

(a) Retail and wholesale gas sales - excludes GSC

	MTD/YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 14	5,217,377	$ 2.65	$ 11	4,193,319	$ 2.64	● $3	● $ 3	● $ -
Commercial	5	2,275,240	2.11	4	1,760,566	2.09	● $1	● $ 1	● $ -
Industrial	0	167,311	1.79	0	145,801	1.82	● $0	● $ -	● $ -
Public Authority	1	384,789	2.08	1	314,549	2.03	● $0	● $ 0	● $ 0
Transportation	1	1,528,085	0.72	0.60	1,449,373	0.43	● $0	● $ -	● $ 1
Ultimate Consumer	$ 21	9,572,802	$ 2.17	$ 16	7,863,608	$ 2.07	● $4	● $ 4	● $ 1

O&M January 2014

($ Millions)

	MTD/YTD								
	Actual	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 17	$ 15	$ (1)	$ 0	$ (0)	$ (1)	$ (0)		$ 0
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	2	2	(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	3	3	(0)	(0)		0	(0)	(0)	(0)
Customer Services	8	7	(1)	0		(0)	(0)	(1)	0
Chief Operations Officer	**36**	**33**	**(2)**	**0**	**(0)**	**(1)**	**(1)**	**(1)**	**(0)**
Information Technology	4	5	1	0		0	(0)		(0)
General Counsel	2	2	0	0		0	0		0
Human Resources	1	1	0	0		0	0		0
Supply Chain	0	0	0	0		(0)	(0)		0
Chief Administrative Officer	**7**	**8**	**1**	**1**		**0**	**(0)**		**0**
Chief Financial Officer	**2**	**2**	**0**	**0**		**(0)**	**0**		**0**
Corporate	**11**	**12**	**1**	**0**		**0**	**0**		**1**
O&M Total MTD	**$ 55**	**$ 55**	**$ (0)**	**$ 1**	**$ (0)**	**$ 0**	**$ (1)**	**$ (1)**	**$ 1**

Financing Activities — January 2014

($ Millions)

Balance Sheet	MTD/YTD Actual	MTD/YTD Budget	MTD/YTD Variance
PCB			
Beg Bal	$ 924.0	$ 924.0	$ 0.0
End Bal	924.0	924.1	0.1
Ave Bal	**$ 924.0**	**$ 924.0**	**$ 0.1**
Interest Exp	**$ 0.8**	**$ 0.9**	**$ 0.2**
Rate	**0.96%**	**1.19%**	**0.23%**
FMB/Sr Nts			
Beg Bal	$ 3,640.9	$ 3,640.9	$ -
End Bal	3,641.0	3,641.0	(0.0)
Ave Bal	**$ 3,640.9**	**$ 3,640.9**	**$ (0.0)**
Interest Exp	**$ 11.5**	**$ 11.6**	**$ 0.1**
Rate	**3.67%**	**3.71%**	**0.05%**
Short-term Debt			
Beg Bal	$ 245.0	$ 245.0	$ -
End Bal	207.0	223.1	16.1
Ave Bal	**$ 226.0**	**$ 234.0**	**$ 8.1**
Interest Exp	**$ 0.2**	**$ 0.3**	**$ 0.2**
Rate	**0.92%**	**1.72%**	**0.80%**
Total End Bal	**$ 4,772.0**	**$ 4,788.2**	**$ 16.2**
Total Average Bal	**$ 4,790.9**	**$ 4,799.0**	**$ 8.1**
Total Expense Excl I/C	**$ 14.0**	**$ 14.3**	**$ 0.3**
Rate	**3.39%**	**3.46%**	**0.07%**

Credit Facilities ($ Millions)	Committed Capacity	Borrowed	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 75		$ 225
LG&E	500	25		475
KU	598	107	$ 198	293
TOTAL	$ 1,398	$ 207	$ 198	$ 993

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud
FFO to Debt - LG&E	34.8%	+0.02
FFO to Debt - KU	29.5%	-0.03
Debt to EBITDA - LG&E (1)	3.03	-0.64
Debt to EBITDA - KU (1)	3.49	-0.23
Debt to Capitalization - LG&E (2)	46.4%	+0.00
Debt to Capitalization - KU (2)	47.1%	-0.00

(1) Actuals represent a trailing 12 months

(2) Excludes purchase accounting adjustments and

Balance Sheet January 2014

($ Millions)

	1/31/2014	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 22	$ 9	$ 13	Higher cash due to higher operational revenue.
Accounts Receivable (Trade)	486	431	55	Higher customer accounts receivable ($29m) and accrued utility revenue ($26m) due to colder than normal weather.
Inventory	243	249	(6)	
Deferred Income Taxes	159	159	(0)	
Prepayments and other current assets	96	106	(10)	Note receivable with PPL partially drawn back to pay for operational expenses for Servco ($16m).
Total Current Assets	1,006	955	51	
Property, Plant, and Equipment	9,590	9,602	(12)	
Intangible Assets	217	217	(0)	
Other Property and Investments	1	1	(0)	
Regulatory Assets	503	496	7	
Goodwill	997	997	0	
Other Long-term Assets	95	96	(1)	
Total Assets	**$ 12,409**	**$ 12,364**	**$ 45**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 368	$ 344	$ 24	Higher accounts payable due to higher than expected gas purchases ($16m) due to colder than normal weather.
Accounts Payable - Affiliated Company	0	0	0	
Customer Deposits	50	50	1	
Derivative Liability	4	4	0	
Accrued Taxes	77	62	14	Higher taxes due to increase in the forecasted pretax income due to colder than normal weather.
Other Current Liabilities	148	151	(3)	
Total Current Liabilities	647	610	37	
Debt - Affiliated Company	-	23	(23)	Budget had a short term debt issuance at LKE Other. An inter company receivable should have been used instead of issuing debt.
Debt (1)	4,772	4,765	6	
Total Debt	4,772	4,788	(16)	
Deferred Tax Liabilities	965	965	0	
Investment Tax Credit	134	134	(0)	
Accum Provision for Pension & Related Benefits	118	117	1	
Asset Retirement Obligation	249	245	4	
Regulatory Liabilities	1,042	1,044	(2)	
Derivative Liability	36	32	4	
Other Liabilities	238	238	(0)	
Total Deferred Credits and Other Liabilities	2,783	2,777	6	
Equity	4,207	4,188	18	
Total Liabilities and Equity	**$ 12,409**	**$ 12,364**	**$ 45**	

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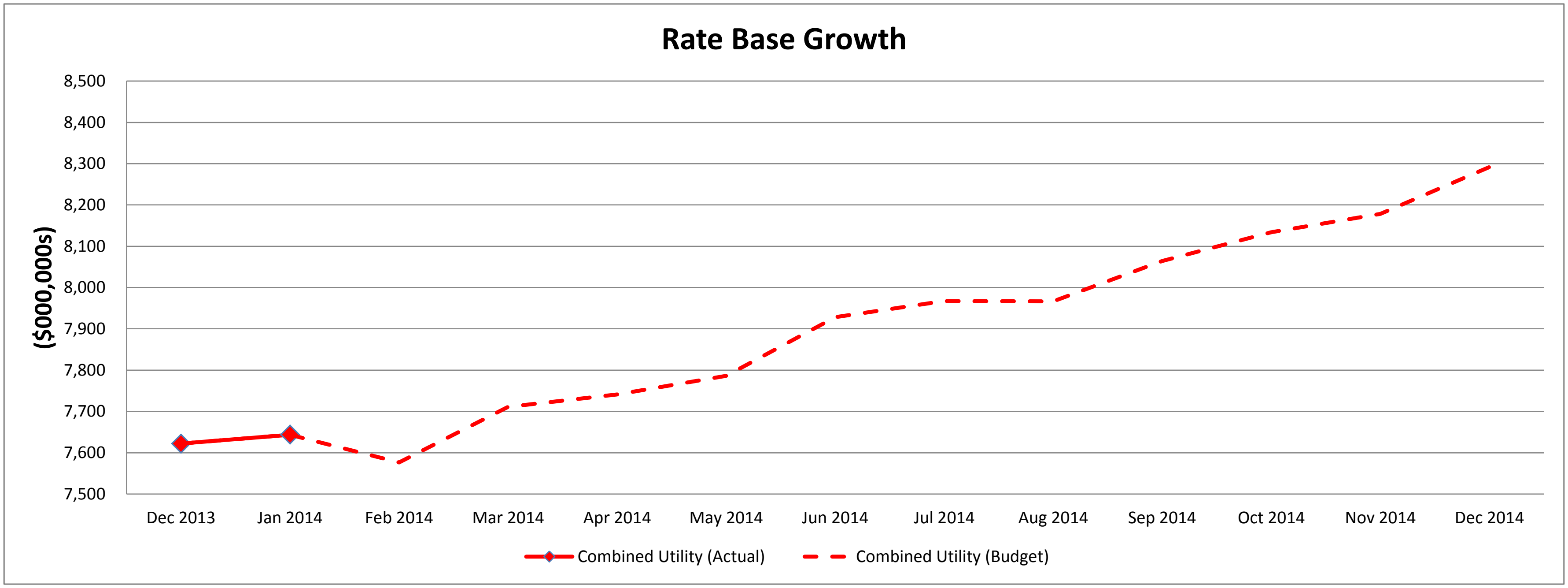
(1) Includes all ST and LT debt. See Financing Activities page for details.


Rate Base Growth
($000,000s)
8,500
8,400
8,300
8,200
8,100
8,000
7,900
7,800
7,700
7,600
7,500
Dec 2013
Jan 2014
Feb 2014
Mar 2014
Apr 2014
May 2014
Jun 2014
Jul 2014
Aug 2014
Sep 2014
Oct 2014
Nov 2014
Dec 2014
Combined Utility (Actual)
Combined Utility (Budget)

Performance Report

February 2014

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Kentucky Regulated Dashboard

February 2014

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.72	0.38	1.13	1.50	1.13	1.29
Employee lost-time incidents	0	0	0	0	0	3
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,990	2,794	6,376	6,012	34,999	34,635
Utility EFOR	2.3%	5.9%	2.8%	5.9%	N/A	5.9%
Utility EAF	86.8%	81.9%	90.4%	87.3%	N/A	82.5%
Steam Fleet Commercial Availability	97.3%	91.5%	98.1%	91.5%	N/A	91.5%
Combined SAIFI	0.05	0.07	0.17	0.13	N/A	1.20
Combined SAIDI (minutes)	5.62	6.13	15.26	11.88	N/A	107.60
GwH Sales						
Residential	1,067	999	2,486	2,113	10,962	10,962
Commercial	619	589	1,363	1,257	7,952	7,952
Industrial	747	720	1,561	1,537	10,011	10,011
Municipals	162	160	356	331	1,969	1,969
Other	226	205	486	441	2,788	2,788
Off-System Sales	77	23	165	107	273	273
Total	2,899	2,696	6,416	5,784	33,954	33,954
Weather-Normalized Sales Growth			**TTM**			
Residential			0.08%			
Commercial			-1.38%			
Industrial			1.55%			
Municipal			-1.09%			
Other			-0.45%			
Total			0.04%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[1]	11.9%	10.6%	14.8%	11.8%	9.0%	8.7%
Electric Margins	$145	$135	$313	$279	$1,689	$1,664
Gas Margins	17	20	43	42	157	157
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$8	$9	$23	$31	$117	$126
ECR	$41	$51	$77	$84	$618	$603
Generation	$4	$11	$6	$16	$120	$122
Transmission	$7	$8	$12	$14	$82	$77
Electric Distribution	$9	$9	$18	$17	$150	$143
Gas Distribution	$4	$5	$8	$10	$81	$80
Customer Services	$1	$1	$1	$3	$18	$20
IT and Other	$3	$4	$5	$8	$41	$50
Total	$78	$98	$149	$184	$1,227	$1,221
O&M ($ millions)[2]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$37	$34	$73	$67	$481	$468
Administrative	8	8	15	16	98	98
Finance	1	1	3	3	19	19
Burdens & Other Charges	12	13	22	24	144	150
Total	$58	$56	$113	$111	$742	$735
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,411	3,524	3,411	3,524	3,549	3,549
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	2	0	3	1	N/A	14
NERC Possible Violations	0	0	0	0	N/A	11

Variance Explanations

- Current month and YTD generation volumes and GWh sales were impacted by cold weather. Generation volumes were also impacted by excellent plant availability.

- Current month margins were higher, driven by favorable weather and system availability, including $6 million from retail electric and $2 million from excess generation sold at market prices. This was partially offset by $3 million from lower gas margins due to a weather normalization adjustment related to unseasonably cold weather.

- Year to date higher margins driven by favorable weather and system availability, including $24 million from retail electric, $6 million from excess generation sold at market prices and $1 million from natural gas volumes.

- Current month capital expenditures were $20 million lower, due primarily to milestone shifts on Ghent environmental air projects.

- YTD capital expenditures were $35 million lower, due primarily to timing of spending on Cane Run U7 (weather related) and milestone shifts on Ghent environmental air projects.

- O&M full year forecast $7 million higher, due primarily to weather related expenses, partially offset by lower labor related costs.

Major Developments

- Following LKE's record-setting energy use in January, the month of February was highlighted by the return of a mini "polar vortex" along with severe weather, including strong winds and ice and snow events. LKE's systems maintained excellent safety performance in meeting the challenges of the severe weather and high demand. New February peak load demand records for KU and the combined system were established at 4,456 MWs and 6,290 MWs. During these difficult conditions, LKE allocated $200,000 to community action groups and non-profit organizations within its service territories, and through its mutual assistance programs released hundreds of personnel to assist with winter restoration efforts in Pennsylvania, South Carolina and Virginia.

- LKE recently marked a significant milestone in its efforts to comply with environmental regulations as it signed its remaining large Engineering, Procurement and Construction (EPC) contract for the 2011 ECR Plan air compliance projects. The Trimble County U1 baghouse EPC contract was executed with AMEC, the company which also serves as the EPC contractor on the Brown U3 baghouse project.

Significant Future Events

- LKE's capital plan remains on schedule for the full year, with heavy construction at Brown, Cane Run, Ghent and Mill Creek. LKE is also seeking permits at various plants. LKE filed the revised landfill permit application for Trimble County in January and will file the associated Division of Water and Corp of Engineer permits in the coming weeks. LKE expects to receive the landfill permit for Brown during the summer. Regarding new generation, LKE will file the air construction permit application for the Green River Natural Gas Combustion Cycle (NGCC) with the Division of Air Quality in March, and will file the Site Assessment Reports to support the CPCN for the Green River NGCC and the Brown Solar Facility with the KPSC in April.

[1] Excludes goodwill and other purchase accounting adjustments.

[2] Net of cost recovery mechanisms.

Income Statement: Actual vs. Budget (Month) February 2014

($ Millions)

	MTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 244	$ 225	$ 19	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Revenues	57	47	9	Due to increasing gas volumes resulting from colder than normal weather.
Total Revenues	301	272	29	
Cost of Sales:				
Fuel Electric Costs	87	76	(11)	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Supply Expenses	39	27	(12)	Due to increasing gas volumes resulting from colder than normal weather.
Purchased Power	4	5	1	
Other Electric Cost	8	9	1	
Total Cost of Sales	139	118	(21)	
Gross Margin:				
Electric Margin	145	135	10	Higher margins driven by favorable weather and system availability , including $6 million from retail electric and $2 million from excess generation sold at market prices.
Gas Margin	17	20	(3)	
Total Gross Margin	162	155	7	
Operating Expenses:				
O&M	58	56	(2)	
Depreciation & Amortization	28	28	0	
Taxes, Other than Income	4	4	(0)	
Total Operating Expenses	90	89	(2)	
Other income	(1)	(1)	0	
EBIT	71	65	6	
Interest Expense	14	14	0	
Income from Ongoing Operations before income taxes	57	51	6	
Income Tax Expense	21	19	(2)	
Net Income (loss) from ongoing operations	**$ 36**	**$ 32**	**$ 4**	
Non Operating Income	0	0	0	
Discontinued Operations	0	0	(0)	
Net Income (loss)	$ 36	$ 32	$ 4	
KY Regulated Financing Costs	(3)	(3)	(0)	
KY Regulated Net Income	$ 33	$ 29	$ 4	
Earnings Per Share	$ 0.05	$ 0.04	$ 0.01	

Income Statement: Actual vs. Budget (YTD) February 2014

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 534	$ 468	$ 66	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Revenues	127	102	26	Due to increasing gas volumes resulting from colder than normal weather.
Total Revenues	661	569	92	
Cost of Sales:				
Fuel Electric Costs	195	160	(34)	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Supply Expenses	84	59	(25)	Due to increasing gas volumes resulting from colder than normal weather.
Purchased Power	10	10	1	
Other Electric Cost	17	18	1	
Total Cost of Sales	305	248	(57)	
Gross Margin:				
Electric Margin	313	279	34	Higher margins driven by favorable weather and system availability, including $24 million from retail electric, $6 million from excess generation sold at market prices
Gas Margin	43	42	1	
Total Gross Margin	356	321	35	
Operating Expenses:				
O&M	113	111	(2)	
Depreciation & Amortization	56	57	1	
Taxes, Other than Income	8	8	(0)	
Total Operating Expenses	178	177	(1)	
Other income	(2)	(2)	0	
EBIT	177	143	34	
Interest Expense	28	29	1	
Income from Ongoing Operations before income taxes	149	114	35	
Income Tax Expense	56	43	(13)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**$ 93**	**$ 71**	**$ 22**	
Non Operating Income	0	-	0	
Discontinued Operations	0	0	(0)	
Net Income (loss)	$ 93	$ 71	$ 22	
KY Regulated Financing Costs	(5)	(5)	(0)	
KY Regulated Net Income	$ 88	$ 66	$ 22	
Earnings Per Share	$ 0.13	$ 0.10	$ 0.03	

Electric Gross Margin

February 2014

($ Millions)

	MTD						YTD					
	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance	Actual	Budget	Unit Variance	Value @	Dollar Variance	Margin Variance
Base Electric Margin:						● $ 6						● $ 24
Energy Volumes (a)	2,822,112	2,672,629	149,483	$ -	$ 5		6,251,349	5,677,246	574,103	$ -	$ 23	
Energy Prices (a)					(1)						(2)	
Customer Charges (Avg. Customers)	941,096	944,714	(3,618)		(0)		940,889	944,713	(3,824)		(0)	
Demand Charges (b)	38	36			2		77	73			3	
ECR:						● $ 0						◆ $ (1)
Average Rate Base	$ 1,167	$ 1,162	$ 5	10.42%	$ -		$ 1,147	$ 1,137	$ 9	10.42%	$ 0.1	
Cost of Capital	10.21%	10.42%	-0.22%	$ 1,167	$ (0.2)		10.21%	10.42%	-0.21%	$ 1,147	(0.3)	
Jurisdictional Factor	85.93%	85.99%	-0.06%	$ 1,167	$ -		84.65%	86.10%	-1.45%	$ 1,147	(0.3)	
Other					$ 0.5						(0.1)	
DSM:						◆ $ (0)						◆ $ (0)
Program Expense (Revenue Net of Expense)	$ -	$ -			$ -		$ (0.1)	$ 0.1			$ (0.2)	
Lost Sales	1.2	1.9			$ (0.7)		2.4	3.7			(1.3)	
Incentive	0.1	0.1			$ -		0.1	0.1			-	
Balancing Adjustment	0.4	-			$ 0.4		1.1	-			1.1	
Net Fuel Recovery	$ (0.3)	$ (0.4)				● $ 0	$ (2)	$ (1)				◆ $ (2)
Purchase Power Demand	(2.1)	(2.4)				● $ 0	(3.6)	(5.0)				● $ 1
Transmission	1.4	0.9				● $ 1	2.9	1.9				● $ 1
Other	(1.1)	(3.4)				● $ 2	(3.4)	(7.5)				● $ 4
Retail Margin Variance						● $ 9						● $ 28
Off-System Margin Variance						● $ 2						● $ 6
Electric Margin Variance						● $ 10						● $ 34

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 52	1,067,426	$ 48.28	$ 48	998,920	$ 48.50	● $3	● $3	◆ ($0)
Commercial	20	619,421	32.45	20	589,230	33.16	● $1	● $1	◆ ($0)
Industrial	7	746,555	8.93	7	719,572	9.00	● $0	● $0	◆ ($0)
Municipals	1	162,377	5.56	1	160,350	5.56	● $0	● $0	● $0
Other	5	226,332	23.76	5	204,557	24.29	● $0	● $1	◆ ($0)
Native Load Total	**$ 85**	**2,822,112**	**$ 29.97**	**$ 80**	**2,672,629**	**$ 30.05**	● **$4**	● **$5**	◆ **($1)**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 120	2,485,633	$ 48.25	$ 103	2,112,770	$ 48.51	● $17	● $18	◆ ($1)
Commercial	44	1,362,534	31.99	42	1,256,525	33.07	● $2	● $4	◆ ($2)
Industrial	14	1,561,179	8.96	14	1,536,561	8.99	● $0	● $0	● $0
Municipals	2	355,958	5.56	2	330,571	5.56	● $0	● $0	● $0
Other	12	486,044	23.77	11	440,819	24.06	● $1	● $1	◆ ($0)
Native Load Total	**$ 191**	**6,251,349**	**$ 30.56**	**$ 170**	**5,677,246**	**$ 30.00**	● **$21**	● **$23**	◆ **($2)**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD Act	MTD Bud	MTD Variance	YTD Act	YTD Bud	YTD Variance
Commercial	13	12	1	26	23	3
Industrial	15	16	(0)	31	31	(0)
Municipals	5	4	0	10	9	1
Other	5	5	0	10	10	0
Native Load Total	**38**	**36**	**2**	**77**	**73**	**3**

Gas Gross Margin February 2014

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		● **$ -**	**$ 10**	**$ 10**		● **$ -**
Gas Supply Costs								
Gas Supply Costs	(39)	(27)	$ (12)		(83)	(59)	$ (24)	
GSC Revenue	38	27	11		82	59	23	
Net Gas Supply Costs				◆ **$ (1)**				◆ **$ (1)**
Retail Gas (a)	**16**	**14**		● **$ 2**	**37**	**31**		● **$ 6**
Wholesale Gas (a)	**-**	**-**		● **$ -**	**-**	**-**		● **$ -**
DSM	**0**	**0**		● **$ 0**	**0**	**0**		● **$ 0**
GLT	**1**	**1**		◆ **$ (0)**	**1**	**1**		◆ **$ (0)**
WNA	**(4)**	**-**		◆ **$ (4)**	**(5)**	**-**		◆ **$ (5)**
Other Margin	**0**	**0**		● **$ 0**	**1**	**0**		● **$ 0**
Gas Margin Variance				◆ **$ (3)**				● **$ 1**

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 10	3,917,938	$ 2.64	$ 9	3,533,914	$ 2.64	● $1	● $ 1	● $ -
Commercial	4	1,736,021	-	3	1,475,867	2.09	● $1	● $ 1	● $ 0
Industrial	0	163,906	2.05	0	122,616	1.79	● $0	● $ 0	● $ -
Public Authority	1	250,479	2.08	1	244,432	2.02	● $0	● $ -	● $ -
Transportation	1	1,375,516	0.73	1.00	1,334,938	0.42	● $0	● $ -	● $ 0
Ultimate Consumer	$ 16	7,443,860	$ 1.64	$ 14	6,711,767	$ 2.05	● $2	● $ 2	● $ 0

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 24	9,135,315	$ 2.64	$ 20	7,727,234	$ 2.64	● $4	● $ 4	● $ -
Commercial	8	4,011,261	-	7	3,236,432	2.09	● $2	● $ 2	● $ -
Industrial	1	331,217	2.03	1	268,417	1.81	● $0	● $ 0	● $ 0
Public Authority	1	635,268	2.07	1	558,981	2.02	● $0	● $ 0	● $ 0
Transportation	2	2,936,253	0.72	2	2,848,760	0.42	● $0	● $ -	● $ 0
Ultimate Consumer	$ 37	17,049,314	$ 1.66	$ 31	14,639,824	$ 2.06	● $6	● $ 6	● $ 1

O&M February 2014

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 17	$ 17	$ (0)	$ 0	$ 1	$ 0	$ (0)		$ (1)
Project Engineering	0	0	0	(0)		0	(0)		0
Transmission	2	2	(0)	(0)		(0)	0		(0)
Energy Supply and Analysis	1	1	(0)	(0)		0	0		(0)
Electric Distribution	8	6	(1)	(1)		(0)	(0)	(0)	(0)
Gas Distribution	3	2	(1)	(0)		(0)	(0)	(0)	(0)
Customer Services	6	6	(0)	(0)		(0)	0	(0)	0
Chief Operations Officer	**37**	**34**	**(3)**	**(1)**	**1**	**(1)**	**(0)**	**(0)**	**(2)**
Information Technology	4	4	(0)	0		(0)	(0)		(0)
General Counsel	2	3	0	0		0	0		0
Human Resources	1	1	0	(0)		0	0		0
Supply Chain	0	0	0	0		0	(0)		0
Chief Administrative Officer	**8**	**8**	**0**	**0**		**(0)**	**(0)**		**0**
Chief Financial Officer	**1**	**1**	**(0)**	**(0)**		**0**	**0**		**(0)**
Corporate	**12**	**13**	**1**	**2**		**0**	**0**		**(1)**
O&M Total MTD	**$ 58**	**$ 56**	**$ (2)**	**$ 1**	**$ 1**	**$ (1)**	**$ (0)**	**$ (0)**	**$ (3)**

	YTD								
	Actual	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 33	$ 32	$ (2)	$ 0	$ 1	$ (1)	$ (1)		$ (1)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	5	4	(0)	(0)		(0)	0		(0)
Energy Supply and Analysis	2	2	(0)	0		(0)	0		(0)
Electric Distribution	13	12	(1)	(1)		0	(0)	(0)	(0)
Gas Distribution	6	5	(1)	(0)		0	(0)	(0)	(1)
Customer Services	14	12	(1)	0		(0)	0	(1)	0
Chief Operations Officer	**73**	**67**	**(6)**	**(1)**	**1**	**(1)**	**(1)**	**(1)**	**(2)**
Information Technology	9	9	0	1		0	(0)		(0)
General Counsel	4	5	1	0		0	0		0
Human Resources	1	1	0	(0)		0	0		0
Supply Chain	1	1	0	0		0	(0)		0
Chief Administrative Officer	**15**	**16**	**1**	**1**		**0**	**(0)**		**0**
Chief Financial Officer	**3**	**3**	**0**	**0**		**0**	**0**		**0**
Corporate	**22**	**24**	**2**	**2**		**0**	**0**		**(1)**
O&M Total YTD	**$ 113**	**$ 111**	**$ (2)**	**$ 2**	**$ 1**	**$ (0)**	**$ (1)**	**$ (1)**	**$ (3)**

Financing Activities February 2014

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance
PCB						
Beg Bal	$ 924.0	$ 924.1	$ 0.1	$ 924.0	$ 924.0	$ 0.0
End Bal	924.0	924.2	0.3	924.0	924.2	0.3
Ave Bal	**$ 924.0**	**$ 924.2**	**$ 0.2**	**$ 924.0**	**$ 924.2**	**$ 0.2**
Interest Exp	**$ 0.8**	**$ 0.9**	**$ 0.2**	**$ 1.5**	**$ 1.9**	**$ 0.4**
Rate	**1.05%**	**1.32%**	**0.27%**	**1.00%**	**1.25%**	**0.25%**
FMB/Sr Nts						
Beg Bal	$ 3,641.0	$ 3,641.0	$ (0.0)	$ 3,640.9	$ 3,640.9	$ -
End Bal	3,641.2	3,641.1	(0.0)	3,641.2	3,641.1	(0.0)
Ave Bal	**$ 3,641.1**	**$ 3,641.1**	**$ (0.0)**	**$ 3,641.0**	**$ 3,641.1**	**$ 0.1**
Interest Exp	**$ 11.5**	**$ 11.6**	**$ 0.1**	**$ 23.0**	**$ 23.3**	**$ 0.3**
Rate	**4.06%**	**4.11%**	**0.05%**	**3.85%**	**3.90%**	**0.05%**
Short-term Debt						
Beg Bal	$ 207.0	$ 223.1	$ 16.1	$ 245.0	$ 245.0	$ -
End Bal	207.0	206.0	(1.0)	207.0	206.0	(1.0)
Ave Bal	**$ 207.0**	**$ 214.6**	**$ 7.6**	**$ 226.0**	**$ 214.6**	**$ (11.4)**
Interest Exp	**$ 0.1**	**$ 0.3**	**$ 0.3**	**$ 0.3**	**$ 0.7**	**$ 0.4**
Rate	**0.35%**	**2.09%**	**1.75%**	**0.90%**	**1.98%**	**1.07%**
Total End Bal	**$ 4,772.1**	**$ 4,771.4**	**$ (0.7)**	**$ 4,772.1**	**$ 4,771.4**	**$ (0.7)**
Total Average Bal	**$ 4,772.1**	**$ 4,779.8**	**$ 7.8**	**$ 4,791.0**	**$ 4,779.8**	**$ (11.2)**
Total Expense Excl I/C	**$ 13.9**	**$ 14.3**	**$ 0.4**	**$ 27.9**	**$ 28.6**	**$ 0.7**
Rate	**3.74%**	**3.85%**	**0.11%**	**3.55%**	**3.65%**	**0.10%**

Credit Facilities ($ Millions)	Committed Capacity	Borrowed	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 75		$ 225
LG&E	500	15		485
KU	598	117	$ 198	283
TOTAL	$ 1,398	$ 207	$ 198	$ 993

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud
FFO to Debt - LG&E	32.6%	+0.00
FFO to Debt - KU	28.3%	+0.00
Debt to EBITDA - LG&E (1)	3.00	-0.67
Debt to EBITDA - KU (1)	3.47	-0.25
Debt to Capitalization - LG&E (2)	46.4%	+0.00
Debt to Capitalization - KU (2)	47.3%	-0.00

(1) Actuals represent a trailing 12 months

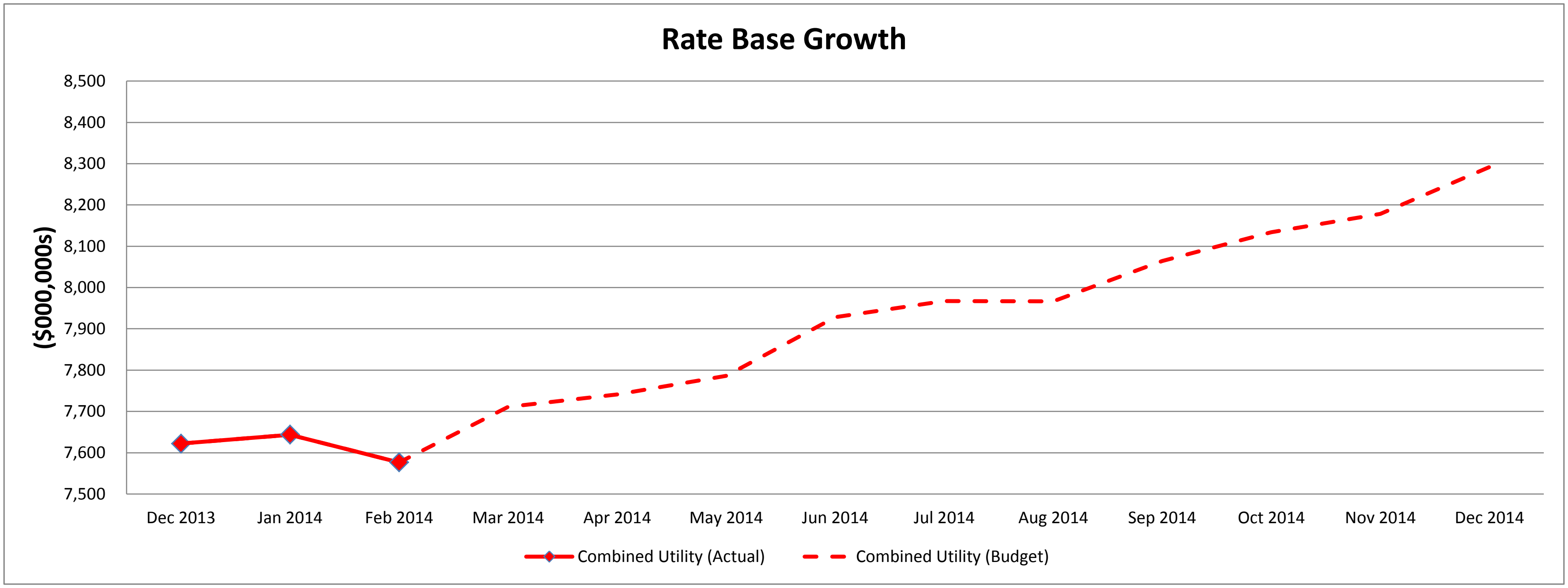
(2) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet February 2014

($ Millions)

	2/28/2014	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 39	$ 24	$ 15	Higher cash due to higher operational revenue.
Accounts Receivable (Trade)	471	412	59	Higher customer accounts receivable ($79m) due to colder than normal weather partially offset by negative accrued utility revenue ($17m).
Inventory	228	233	(6)	
Deferred Income Taxes	159	159	(0)	
Prepayments and other current assets	120	105	15	Higher accounts receivable ($28m) offset by note receivable ($17m).
Total Current Assets	1,017	933	84	
Property, Plant, and Equipment	9,640	9,672	(32)	
Intangible Assets	213	213	(0)	
Other Property and Investments	1	1	(0)	
Regulatory Assets	509	496	13	Higher GSC ($10m) and FAC ($3m).
Goodwill	997	997	0	
Other Long-term Assets	95	95	(1)	
Total Assets	**$ 12,471**	**$ 12,407**	**$ 64**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 340	$ 341	$ (1)	
Accounts Payable - Affiliated Company	104	0	104	Dividend payable ($104m) issued to PPL based on Q4 2013 net income.
Customer Deposits	51	50	1	
Derivative Liability	4	4	0	
Accrued Taxes	102	82	20	Higher taxes due to increase in the forecasted pretax income due to colder than normal weather.
Other Current Liabilities	175	165	10	
Total Current Liabilities	775	641	135	
Debt - Affiliated Company	-	23	(23)	Budget had a short term debt issuance at LKE Other. An inter company receivable should have been used instead of issuing debt.
Debt [(1)]	4,772	4,748	24	Higher than budgeted Commercial Paper ($24m).
Total Debt	4,772	4,771	1	
Deferred Tax Liabilities	965	965	1	
Investment Tax Credit	134	134	(0)	
Accum Provision for Pension & Related Benefits	119	118	1	
Asset Retirement Obligation	250	246	4	
Regulatory Liabilities	1,041	1,041	(0)	
Derivative Liability	36	32	4	
Other Liabilities	240	239	2	
Total Deferred Credits and Other Liabilities	2,786	2,775	11	
Equity	4,138	4,220	(82)	
Total Liabilities and Equity	**$ 12,471**	**$ 12,407**	**$ 64**	

(1) Includes all ST and LT debt. See Financing Activities page for details.


Rate Base Growth
($000,000s)
8,500
8,400
8,300
8,200
8,100
8,000
7,900
7,800
7,700
7,600
7,500
Dec 2013
Jan 2014
Feb 2014
Mar 2014
Apr 2014
May 2014
Jun 2014
Jul 2014
Aug 2014
Sep 2014
Oct 2014
Nov 2014
Dec 2014
Combined Utility (Actual)
Combined Utility (Budget)

Performance Report

March 2014

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Kentucky Regulated Dashboard

March 2014

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.82	0.68	1.37	1.18	1.37	1.29
Employee lost-time incidents	0	0	0	0	0	3
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,859	2,673	9,449	8,686	35,518	34,780
Utility EFOR	2.3%	5.9%	2.7%	5.9%	N/A	5.9%
Utility EAF	72.7%	68.1%	84.3%	80.8%	N/A	82.5%
Steam Fleet Commercial Availability	98.7%	91.5%	98.3%	91.5%	N/A	91.5%
Combined SAIFI	0.06	0.08	0.23	0.21	N/A	1.20
Combined SAIDI (minutes)	4.43	7.76	19.69	19.64	N/A	107.60
GwH Sales						
Residential	934	919	3,420	3,032	11,349	10,962
Commercial	626	601	1,989	1,858	8,083	7,952
Industrial	809	763	2,370	2,300	10,082	10,011
Municipals	156	158	512	488	1,993	1,969
Other	230	213	716	654	2,850	2,788
Off-System Sales	53	1	218	108	345	273
Total	2,809	2,655	9,225	8,439	34,702	33,954
Weather-Normalized Sales Growth			**TTM**			
Residential			-1.20%			
Commercial			-1.49%			
Industrial			1.59%			
Municipal			-2.02%			
Other			-0.36%			
Total			-0.44%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[(1)]	8.4%	7.2%	12.7%	10.1%	9.1%	8.7%
Electric Margins	$135	$132	$448	$411	$1,689	$1,664
Gas Margins	16	16	59	58	157	157
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$14	$16	$37	$47	$117	$126
ECR	$50	$54	$127	$138	$618	$603
Generation	$6	$6	$11	$23	$121	$121
Transmission	$7	$6	$20	$20	$85	$77
Electric Distribution	$8	$12	$26	$29	$148	$143
Gas Distribution	$5	$6	$12	$16	$81	$80
Customer Services	$1	$1	$2	$4	$18	$20
IT and Other	$3	$4	$8	$12	$45	$50
Total	$93	$105	$242	$289	$1,231	$1,221
O&M ($ millions)[(2)]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$44	$46	$117	$114	$481	$468
Administrative	8	8	23	24	98	98
Finance	2	2	5	5	19	19
Burdens & Other Charges	16	13	38	38	144	150
Total	$69	$69	$183	$181	$742	$735
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,432	3,527	3,432	3,527	3,546	3,549
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	2	3	3	N/A	14
NERC Possible Violations	0	0	0	0	N/A	11

Variance Explanations

- YTD generation volumes and GWh sales were impacted by cold weather. Generation volumes were also impacted by excellent plant availability.

- YTD higher margins driven by favorable weather and system availability, including $26 million from retail electric sales, $7 million from off-system sales and $4 million from other margin components.

- YTD Capital expenditures were $47m lower than budget YTD due primarily to timing of spending on Cane Run Unit 7 and milestone shifts on Ghent environmental air projects, partially offset by higher than budgeted spending on Mill Creek environmental air projects due to delays in 2013.

- O&M full year forecast $7 million higher, due primarily to the impacts of the cold winter (bad debt expense, storms expense and plant maintenance), partially offset by lower pension and post-retirement benefit expenses.

Major Developments

- 2014 has been marked by historically cold weather and increased electricity consumption. The month of March maintained this winter-long trend with colder than normal temperatures and the establishment of a new March peak load of 4,092 MWs for the KU system.

- By letter dated March 17, 2014, the Sierra Club notified LG&E of its intent to sue LG&E using the citizen suit provisions under the Clean Water Act ("Notice"). In its Notice, the Sierra Club alleges that LG&E's Pollutant Discharge Elimination System Permit ("Permit") only allows "an occasional discharge" directly into the Ohio River from Outfall 002. The Sierra Club further alleges that LG&E has discharged from Outfall 002 directly into the Ohio River "on an almost daily basis." In response to the notice and consistent with LG&E's position, Bruce Scott, the Commissioner of the Kentucky Department for Environmental Protection, has publicly stated that LG&E's Permit does not contain a restriction on the frequency of discharge from Outfall 002 into the Ohio River and that LG&E is in compliance with its Permit. Notwithstanding the regulatory assurances that we are in compliance, we do expect the Sierra Club to initiate the lawsuit as a part of its nationwide campaign against fossil fuels.

Significant Future Events

- LKE's capital plan remains on schedule in 2014 with heavy construction at Brown, Cane Run, Ghent, and Mill Creek. LKE is also seeking permits at various plants. LKE filed the revised landfill permit application for Trimble County in January and will file the associated Division of Water and Corp of Engineer permits in the coming weeks. The landfill permit for Brown is expected during the summer. Regarding the Green River NGCC and the Brown Solar Facility, LKE is currently reviewing the Site Assessment Reports which will be filed with the KPSC in April. A formal hearing on the matter is scheduled to take place July 8 – July 10.

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(1) Excludes goodwill and other purchase accounting adjustments.

(2) Net of cost recovery mechanisms.

Income Statement: Actual vs. Budget (Month)

March 2014

($ Millions)

	MTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 232	$ 223	$ 9	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Revenues	42	35	7	Due to increasing gas volumes resulting from colder than normal weather.
Total Revenues	274	257	16	
Cost of Sales:				
Fuel Electric Costs	84	75	(9)	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Supply Expenses	26	19	(7)	Due to increasing gas volumes resulting from colder than normal weather.
Purchased Power	5	7	2	
Other Electric Cost	7	8	1	
Total Cost of Sales	123	110	(13)	
Gross Margin:				
Electric Margin	135	132	3	
Gas Margin	16	16	0	
Total Gross Margin	151	148	3	
Operating Expenses:				
O&M	69	69	(0)	
Depreciation & Amortization	28	28	0	
Taxes, Other than Income	4	4	(0)	
Total Operating Expenses	102	102	0	
Other income	(1)	(1)	0	
EBIT	49	45	4	
Interest Expense	14	14	1	
Income from Ongoing Operations before income taxes	35	31	4	
Income Tax Expense	13	11	(2)	
Net Income (loss) from ongoing operations	**$ 22**	**$ 19**	**$ 2**	
Non Operating Income	0	0	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 22	$ 19	$ 2	
KY Regulated Financing Costs	(3)	(3)	(0)	
KY Regulated Net Income	$ 19	$ 17	$ 2	
Earnings Per Share	$ 0.03	$ 0.02	$ 0.00	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) March 2014

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 766	$ 691	$ 75	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Revenues	169	136	32	Due to increasing gas volumes resulting from colder than normal weather.
Total Revenues	935	827	108	
Cost of Sales:				
Fuel Electric Costs	279	235	(44)	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Supply Expenses	110	78	(32)	Due to increasing gas volumes resulting from colder than normal weather.
Purchased Power	15	18	3	
Other Electric Cost	24	27	3	
Total Cost of Sales	427	358	(70)	
Gross Margin:				
Electric Margin	448	411	37	Higher margins driven by favorable weather and system availability, including $26 million from retail electric energy and demand charge revenues, $7 million from excess generation sold at market prices and $4 million from other margin components.
Gas Margin	59	58	1	
Total Gross Margin	507	469	38	
Operating Expenses:				
O&M	183	181	(2)	
Depreciation & Amortization	84	85	1	
Taxes, Other than Income	13	13	(0)	
Total Operating Expenses	280	279	(1)	
Other income	(2)	(3)	1	
EBIT	225	188	38	
Interest Expense	42	43	1	
Income from Ongoing Operations before income taxes	184	145	39	
Income Tax Expense	69	55	(14)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**$ 115**	**$ 90**	**$ 24**	
Non Operating Income	0	-	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 115	$ 90	$ 25	
KY Regulated Financing Costs	(8)	(8)	(0)	
KY Regulated Net Income	$ 107	$ 82	$ 25	
Earnings Per Share	$ 0.16	$ 0.12	$ 0.04	

Note: Schedules may not sum due to rounding.

Income Statement: Forecast vs. Budget March 2014

($ Millions)

	Full Year			
	Q1 Forecast	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,877	$ 2,815	$ 62	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Revenues	351	318	32	Due to increasing gas volumes resulting from colder than normal weather.
Total Revenues	3,227	3,134	94	
Cost of Sales:				
Fuel Electric Costs	996	953	(43)	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Supply Expenses	193	162	(32)	Due to increasing gas volumes resulting from colder than normal weather.
Purchased Power	69	72	3	
Other Electric Cost	124	127	3	
Total Cost of Sales	1,381	1,313	(68)	
Gross Margin:				
Electric Margin	1,689	1,664	25	Higher margins driven by favorable weather and system availability.
Gas Margin	158	157	1	
Total Gross Margin	1,846	1,820	26	
Operating Expenses:				
O&M	742	735	(7)	Due primarily to weather related expenses, partially offset by lower labor related costs.
Depreciation & Amortization	343	344	1	
Taxes, Other than Income	51	51	0	
Total Operating Expenses	1,135	1,130	(6)	
Other income	(6)	(7)	0	
EBIT	705	684	21	
Interest Expense	171	172	1	
Income from Ongoing Operations before income taxes	533	511	22	
Income Tax Expense	200	192	(8)	
Net Income (loss) from ongoing operations	**$ 333**	**$ 319**	**14**	
Non Operating Income	0	-	0	
Discontinued Operations	0	0	(0)	
Net Income (loss)	$ 334	$ 320	$ 14	
KY Regulated Financing Costs	(31)	(31)	-	
KY Regulated Net Income	$ 302	$ 288	$ 14	
Earnings Per Share	$ 0.45	$ 0.43	$ 0.02	

Note: Schedules may not sum due to rounding.

Electric Gross Margin March 2014

($ Millions)

	MTD						YTD					
	Actual	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**	**Actual**	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**
Base Electric Margin:						● **$ 2**						● **$ 26**
Energy Volumes (a)	2,755,887	2,653,839	102,048	$ -	$ 2		9,007,235	8,331,084	676,151	$ -	$ 25	
Energy Prices (a)					(1)						(3)	
Customer Charges (Avg. Customers)	939,361	944,719	(5,358)		(0)		940,379	944,715	(4,335)		(0)	
Demand Charges (b)	37	36			0		113	110			4	
ECR:						◆ **$ (1)**						◆ **$ (1)**
Average Rate Base	$ 1,216	$ 1,215	$ 1	10.37%	$ -		$ 1,170	$ 1,163	$ 7	10.40%	$ 0.1	
Cost of Capital	10.21%	10.37%	-0.16%	$ 1,216	$ (0.1)		10.21%	10.40%	-0.19%	$ 1,170	(0.5)	
Jurisdictional Factor	86.12%	86.95%	-0.83%	$ 1,216	$ (0.1)		85.16%	86.40%	-1.24%	$ 1,170	(0.4)	
Other					$ (0.3)						(0.4)	
DSM:						◆ **$ (1)**						◆ **$ (2)**
Program Expense (Revenue Net of Expense)	$ -	$ -			$ -		$ (0.1)	$ 0.1			$ (0.2)	
Lost Sales	1.5	1.9			$ (0.4)		3.8	5.6			(1.8)	
Incentive	0.1	0.1			$ -		0.2	0.2			-	
Balancing Adjustment	(0.8)	-			$ (0.8)		0.3	-			0.3	
Net Fuel Recovery	$ (1.0)	$ (0.4)				◆ **$ (1)**	$ (3)	$ (1)				◆ **$ (2)**
Purchase Power Demand	(2.3)	(2.6)				● **$ 0**	(5.9)	(7.6)				● **$ 2**
Transmission	0.9	0.6				● **$ 0**	3.8	2.6				● **$ 1**
Other	(0.8)	(2.5)				● **$ 2**	(4.2)	(10.0)				● **$ 6**
Retail Margin Variance						● **$ 2**						● **$ 29**
Off-System Margin Variance						● **$ 2**						● **$ 7**
Electric Margin Variance						● **$ 3**						● **$ 37**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			**Budget**			**Variance**		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 45	934,022	$ 48.43	$ 45	919,368	$ 48.59	● $1	● $1	◆ ($0)
Commercial	20	626,375	31.51	20	601,113	32.86	◆ ($0)	● $1	◆ ($1)
Industrial	7	809,027	8.95	7	763,013	8.97	● $0	● $0	● $0
Municipals	1	156,287	5.56	1	157,532	5.56	● $0	● $0	● $0
Other	6	230,176	24.63	5	212,813	23.99	● $1	● $0	● $0
Native Load Total	**$ 79**	**2,755,887**	**$ 28.58**	**$ 77**	**2,653,839**	**$ 29.11**	● **$1**	● **$2**	◆ **($1)**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			**Budget**			**Variance**		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 165	3,419,656	$ 48.30	$ 147	3,032,138	$ 48.54	● $18	● $19	◆ ($1)
Commercial	63	1,988,909	31.84	61	1,857,638	33.00	● $2	● $4	◆ ($2)
Industrial	21	2,370,205	8.96	21	2,299,574	8.98	● $1	● $1	◆ ($0)
Municipals	3	512,244	5.56	3	488,103	5.56	● $0	● $0	● $0
Other	17	716,221	24.05	16	653,632	24.04	● $2	● $2	● $0
Native Load Total	**$ 270**	**9,007,235**	**$ 29.95**	**$ 248**	**8,331,084**	**$ 29.71**	● **$22**	● **$25**	◆ **($3)**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD			YTD		
	Act	**Bud**	**Variance**	**Act**	**Bud**	**Variance**
Commercial	12	11	1	38	35	3
Industrial	15	16	(1)	46	47	(1)
Municipals	4	4	-	14	13	1
Other	5	5	0	16	15	1
Native Load Total	**37**	**36**	**0**	**113**	**110**	**4**

Gas Gross Margin March 2014

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	$ 5	$ 5		🟢 $ -	$ 15	$ 15		🟢 $ 0
Gas Supply Costs								
Gas Supply Costs	(26)	(19)	$ (7)		(109)	(78)	$ (31)	
GSC Revenue	26	19	7		108	78	30	
Net Gas Supply Costs				♦ $ (0)				♦ $ (1)
Retail Gas (a)	12	10		🟢 $ 2	49	41		🟢 $ 8
Wholesale Gas (a)	-	-		🟢 $ -	-	-		🟢 $ -
DSM	(0)	0		♦ $ (0)	0	0		🟢 $ 0
GLT	1	1		♦ $ (0)	1	2		♦ $ (0)
WNA	(2)	-		♦ $ (2)	(6)	-		♦ $ (6)
Other Margin	0	0		🟢 $ 0	1	0		🟢 $ 0
Gas Margin Variance				🟢 $ 0				🟢 $ 1

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 8	2,872,103	$ 2.65	$ 6	2,382,018	$ 2.64	🟢 $1	🟢 $ 1	🟢 $ -
Commercial	3	1,265,813	2.05	2	1,004,319	2.09	🟢 $1	🟢 $ 1	🟢 $ -
Industrial	0	123,039	1.63	0	100,761	1.98	🟢 $0	🟢 $ -	🟢 $ -
Public Authority	0	212,260	1.88	0	177,798	2.25	🟢 $0	🟢 $ 0	♦ $ (0)
Transportation	1	1,282,203	0.86	0.90	1,220,509	0.74	🟢 $0	♦ $ (0)	🟢 $ 0
Ultimate Consumer	$ 12	5,755,418	$ 2.07	$ 10	4,885,405	$ 2.03	🟢 $2	🟢 $ 2	🟢 $ 0

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 32	12,007,418	$ 2.64	$ 27	7,727,234	$ 2.64	🟢 $5	🟢 $ 5	🟢 $ -
Commercial	11	5,277,074	2.08	9	3,236,432	2.09	🟢 $2	🟢 $ 2	🟢 $ -
Industrial	1	454,256	1.98	1	268,417	1.81	🟢 $0	🟢 $ 0	🟢 $ -
Public Authority	2	847,528	2.01	2	558,981	2.02	🟢 $0	🟢 $ 0	🟢 $ -
Transportation	3	4,218,456	0.81	3	2,848,760	0.42	🟢 $0	♦ $ (0)	🟢 $ 1
Ultimate Consumer	$ 49	22,804,732	$ 2.14	$ 41	14,639,824	$ 2.06	🟢 $8	🟢 $ 7	🟢 $ 1

O&M March 2014

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 24	$ 28	$ 4	$ 0	$ 5	$ 0	$ (0)		$ (0)
Project Engineering	0	0	(0)	0		(0)	(0)		0
Transmission	2	2	0	0		(0)	0		0
Energy Supply and Analysis	1	1	0	0		0	0		0
Electric Distribution	8	6	(2)	0		(2)	0	0	(0)
Gas Distribution	3	2	(0)	(0)		(0)	0	(0)	(0)
Safety and Security	0	0	(0)	(0)		(0)	(0)	0	(0)
Customer Services	7	6	(0)	0		(0)	0	(0)	(0)
Chief Operations Officer	**44**	**46**	**2**	**0**	**5**	**(3)**	**(0)**	**(0)**	**(0)**
Information Technology	4	5	0	0		0	(0)		0
General Counsel	3	3	(0)	0		(0)	0		(0)
Human Resources	1	1	0	(0)		(0)	(0)		0
Supply Chain	0	0	0	0		(0)	0		0
Chief Administrative Officer	**8**	**8**	**0**	**0**		**(0)**	**(0)**		**0**
Chief Financial Officer	**2**	**2**	**(0)**	**0**		**0**	**0**		**(0)**
Corporate	**16**	**13**	**(2)**	**(0)**		**0**	**0**		**(3)**
O&M Total MTD	**$ 69**	**$ 69**	**$ (0)**	**$ 1**	**$ 5**	**$ (3)**	**$ (0)**	**$ (0)**	**$ (3)**

	YTD								
	Actual	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 57	$ 60	$ 3	$ (1)	$ 5	$ (1)	$ (0)		$ 0
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	7	7	(0)	(0)		(0)	0		(0)
Energy Supply and Analysis	2	2	0	0		0	0		0
Electric Distribution	21	18	(3)	(1)		(2)	(0)	(0)	(0)
Gas Distribution	8	7	(1)	(0)		0	(0)	(0)	(1)
Safety and Security	1	0	(0)	(0)		(0)	0	0	(0)
Customer Services	20	19	(2)	0		(0)	0	(2)	0
Chief Operations Officer	**117**	**114**	**(4)**	**(3)**	**5**	**(4)**	**(0)**	**(2)**	**(1)**
Information Technology	13	14	1	1		0	(0)		(0)
General Counsel	7	8	0	0		(0)	0		0
Human Resources	2	2	0	(0)		0	0		0
Supply Chain	1	1	0	0		(0)	(0)		0
Chief Administrative Officer	**23**	**24**	**1**	**1**		**(0)**	**(0)**		**0**
Chief Financial Officer	**5**	**5**	**0**	**0**		**0**	**0**		**(0)**
Corporate	**38**	**38**	**(0)**	**2**		**1**	**0**		**(3)**
O&M Total YTD	**$ 183**	**$ 181**	**$ (2)**	**$ 1**	**$ 5**	**$ (3)**	**$ 0**	**$ (2)**	**$ (4)**

	Full Year								
	Forecast	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 246	$ 245	$ (0)	$ 3	$ (0)	$ (3)	$ 1		$ (1)
Project Engineering	1	1	0	(0)		(0)	(0)		0
Transmission	29	29	(1)	(0)		(0)	(0)		(0)
Energy Supply and Analysis	9	9	0	0		0	0		0
Electric Distribution	74	72	(1)	2		(3)	0	0	(0)
Gas Distribution	32	32	(0)	(0)		(0)	0	0	(0)
Safety and Security	3	0	(3)	(3)		(0)	(0)	0	0
Customer Services	87	79	(8)	(0)		(3)	0	(4)	(0)
Chief Operations Officer	**481**	**468**	**(13)**	**2**	**(0)**	**(10)**	**1**	**(4)**	**(2)**
Information Technology	55	55	0	1		(0)	(0)		(0)
General Counsel	32	32	0	0		0	0		0
Human Resources	8	8	0	0		0	0		0
Supply Chain	4	4	0	0		0	0		0
Chief Administrative Officer	**98**	**98**	**0**	**1**		**0**	**(0)**		**(0)**
Chief Financial Officer	**19**	**19**	**0**	**0**		**0**	**0**		**(0)**
Corporate	**144**	**150**	**6**	**7**		**(0)**	**(0)**	**0**	**(1)**
O&M Total Full Year	**$ 742**	**$ 735**	**$ (7)**	**$ 9**	**$ (0)**	**$ (10)**	**$ 1**	**$ (4)**	**$ (3)**

Note: Schedules may not sum due to rounding.

Financing Activities March 2014

($ Millions)

	MTD			YTD			Full Year		
Balance Sheet	**Actual**	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**	**Forecast**	**Budget**	**Variance**
PCB									
Beg Bal	$ 924.0	$ 924.2	$ 0.3	$ 924.0	$ 924.0	$ 0.0	$ 924.0	$ 924.0	$ -
End Bal	924.0	924.4	0.4	924.0	924.4	0.4	926.0	924.9	(1.1)
Ave Bal	**$ 924.0**	**$ 924.3**	**$ 0.3**	**$ 924.0**	**$ 924.2**	**$ 0.3**	**$ 924.7**	**$ 924.6**	**$ (0.2)**
Interest Exp	**$ 0.8**	**$ 0.9**	**$ 0.2**	**$ 2.3**	**$ 2.8**	**$ 0.6**	**$ 10.8**	**$ 11.3**	**$ 0.6**
Rate	**0.95%**	**1.19%**	**0.23%**	**0.99%**	**1.23%**	**0.24%**	**1.17%**	**1.23%**	**0.06%**
FMB/Sr Nts									
Beg Bal	$ 3,641.2	$ 3,641.1	$ (0.0)	$ 3,640.9	$ 3,640.9	$ -	$ 3,640.9	$ 3,640.9	$ -
End Bal	3,641.3	3,641.3	(0.0)	3,641.3	3,641.3	(0.0)	3,642.6	3,642.5	(0.0)
Ave Bal	**$ 3,641.2**	**$ 3,641.2**	**$ (0.0)**	**$ 3,641.1**	**$ 3,641.1**	**$ 0.1**	**$ 3,641.8**	**$ 3,641.8**	**$ (0.0)**
Interest Exp	**$ 11.5**	**$ 11.6**	**$ 0.1**	**$ 34.5**	**$ 34.9**	**$ 0.4**	**$ 140.9**	**$ 141.4**	**$ 0.4**
Rate	**3.67%**	**3.71%**	**0.05%**	**3.79%**	**3.84%**	**0.05%**	**3.87%**	**3.88%**	**0.01%**
Short-term Debt									
Beg Bal	$ 207.0	$ 206.0	$ (1.0)	$ 245.0	$ 245.0	$ -	$ 245.0	$ 245.0	$ -
End Bal	200.0	265.8	65.9	200.0	265.8	65.9	543.4	527.8	(15.6)
Ave Bal	**$ 203.5**	**$ 235.9**	**$ 32.5**	**$ 222.5**	**$ 231.7**	**$ 9.2**	**$ 368.1**	**$ 356.8**	**$ (11.3)**
Interest Exp	**$ 0.1**	**$ 0.4**	**$ 0.3**	**$ 0.5**	**$ 1.1**	**$ 0.6**	**$ 3.4**	**$ 3.6**	**$ 0.2**
Rate	**0.33%**	**1.82%**	**1.49%**	**0.90%**	**1.84%**	**0.94%**	**0.91%**	**1.00%**	**0.09%**
Total End Bal	**$ 4,765.3**	**$ 4,831.5**	**$ 66.2**	**$ 4,765.3**	**$ 4,831.5**	**$ 66.2**	**$ 5,112.0**	**$ 5,095.3**	**$ (16.7)**
Total Average Bal	**$ 4,768.7**	**$ 4,801.5**	**$ 32.7**	**$ 4,787.5**	**$ 4,797.0**	**$ 9.5**	**$ 4,934.7**	**$ 4,923.2**	**$ (11.5)**
Total Expense Excl I/C	**$ 13.8**	**$ 14.3**	**$ 0.5**	**$ 41.7**	**$ 42.9**	**$ 1.2**	**$ 171.2**	**$ 172.4**	**$ 1.2**
Rate	**3.37%**	**3.47%**	**0.10%**	**3.48%**	**3.58%**	**0.10%**	**3.47%**	**3.50%**	**0.03%**

Credit Facilities ($ Millions)	**Committed Capacity**	**Borrowed**	**Letters of Credit Issued**	**Unused Capacity**
LKE	$ 300	$ 75		$ 225
LG&E	500	15		485
KU	598	110	$ 198	290
TOTAL	$ 1,398	$ 200	$ 198	$ 1,000

Credit Metrics	**YTD**		**Full Year**	
($ Millions)	**Actual**	**+/- Bud**	**Forecast**	**+/- Bud**
FFO to Debt - LG&E	30.5%	+0.01	21.6%	-0.01
FFO to Debt - KU	27.5%	+0.02	22.7%	-0.01
Debt to EBITDA - LG&E (1)	3.03	-0.64	3.59	-0.07
Debt to EBITDA - KU (1)	3.47	-0.26	3.67	-0.05
Debt to Capitalization - LG&E (2)	46.2%	+0.01	47.0%	-0.00
Debt to Capitalization - KU (2)	46.6%	-0.01	47.0%	-0.00

(1) Actuals represent a trailing 12 months

(2) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet — March 2014

($ Millions)

	3/31/2014	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 30	$ 30	$ 1	
Accounts Receivable (Trade)	414	416	(3)	
Inventory	225	226	(1)	
Deferred Income Taxes	139	159	(20)	Deferred Income Taxes reclassified from asset to liability Deferred Tax Liabilities.
Prepayments and other current assets	52	103	(51)	Lower notes receivable from affiliate ($66m).
Total Current Assets	860	934	(74)	
Property, Plant, and Equipment	9,704	9,748	(44)	Lower CWIP ($147m) partially offset by higher completed construction electric ($73m) and electric plant in service ($24m)
Intangible Assets	209	209	(0)	
Other Property and Investments	1	1	(0)	
Regulatory Assets	506	497	8	
Goodwill	997	997	0	
Other Long-term Assets	95	95	(0)	
Total Assets	**$ 12,371**	**$ 12,482**	**$ (111)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 344	$ 338	$ 6	
Accounts Payable - Affiliated Company	0	0	0	
Customer Deposits	50	50	1	
Derivative Liability	4	4	0	
Accrued Taxes	25	17	8	
Other Current Liabilities	146	152	(6)	
Total Current Liabilities	569	560	10	
Debt - Affiliated Company	-	41	(41)	Budget had a short term debt issuance at LKE Other. An inter company receivable should have been used instead of issuing debt.
Debt (1)	4,765	4,791	(26)	Lower issuance of Commercial Paper ($26m) due to lower pension payments and lower capex payments at utilities.
Total Debt	4,765	4,831	(66)	
Deferred Tax Liabilities	1,021	1,041	(20)	Deferred Tax Liabilities reclassified from liability to asset as Deferred Income Taxes.
Investment Tax Credit	134	134	(0)	
Accum Provision for Pension & Related Benefits	119	119	1	
Asset Retirement Obligation	251	246	5	
Regulatory Liabilities	1,036	1,037	(1)	
Derivative Liability	36	32	3	
Other Liabilities	240	236	4	
Total Deferred Credits and Other Liabilities	2,837	2,845	(8)	
Equity	4,200	4,245	(46)	
Total Liabilities and Equity	**$ 12,371**	**$ 12,482**	**$ (111)**	

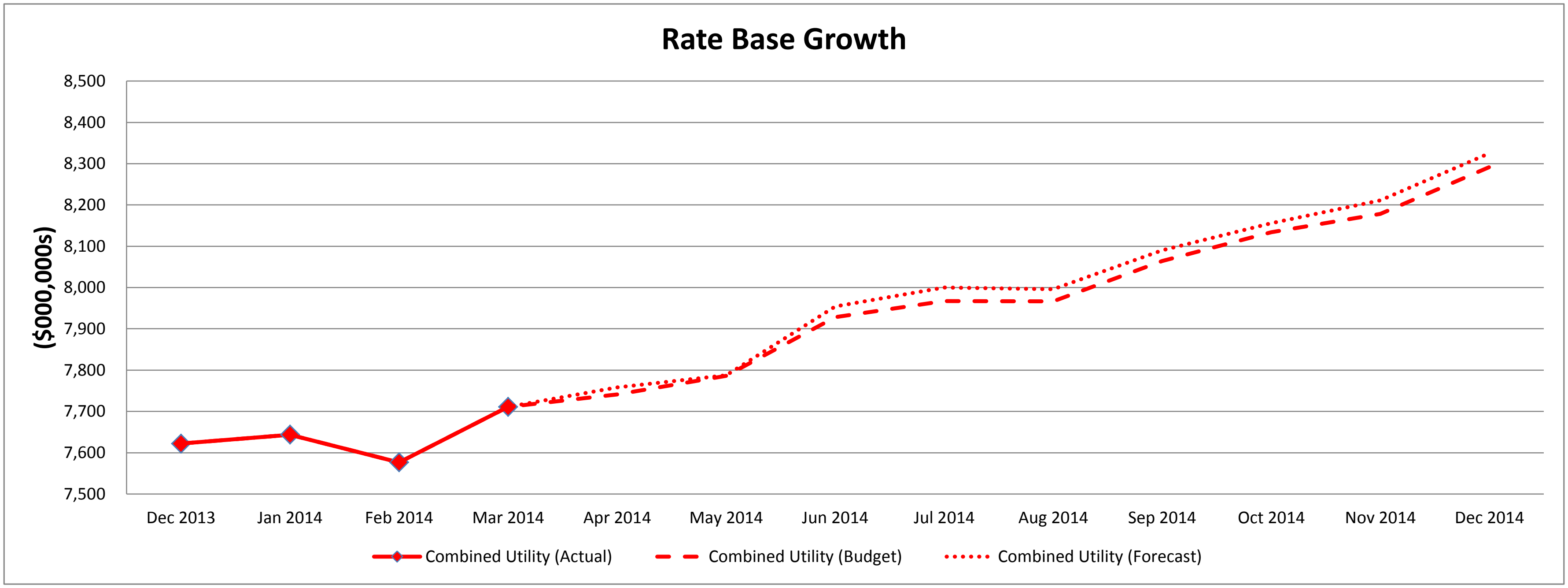
(1) Includes all ST and LT debt. See Financing Activities page for details.

Note: Schedules may not sum due to rounding.

Cash Flow

March 2014

YTD	Actual	Budget	Variance	Comments
Net Income	115	90	24	Mostly due to higher electric and gas volumes resulting from colder than normal weather. See income statement for more details.
Depreciation	92	89	3	
Deferred Income Taxes	74	75	(0)	
Other Balance Sheet Movements	(15)	(10)	(5)	
Funds From Operations	**265**	**243**	**22**	
Changes in accounts receivables	(4)	(7)	3	
Changes in inventories	53	52	1	
Change in Accounts Payable	(5)	(32)	27	Higher accounts payable due to higher than expected gas purchases due to colder than normal weather.
Change in Working Capital	**44**	**13**	**30**	
Operating Cash flow	**309**	**257**	**52**	
Capex	(272)	(289)	17	CapEx lower due to timing of spending on Cane Run Unit 7 and milestone shifts on Ghent environmental air projects.
Other Investing	68	0	68	LKE cash from tax settlements with PPL.
Loans to Affiliates	0	0	0	
Investing Cash flow	**(205)**	**(289)**	**84**	
Dividends	(104)	(61)	(43)	Higher due to liquidity of LKE cash related to PPL tax settlements.
Equity Infusion	40	67	(27)	Budgeted KU and LGE capital distribution but only made distribution to KU.
Net Borrowings	(45)	21	(66)	Lower issuance of CP due to lower pension payments and lower capex payments at utilities.
Other	0	0	0	
Financing Cash flow	**(109)**	**28**	**(137)**	
Net increase (decrease) in cash	**(5)**	**(5)**	**(0)**	


Rate Base Growth
($000,000s)
8,500
8,400
8,300
8,200
8,100
8,000
7,900
7,800
7,700
7,600
7,500
Dec 2013
Jan 2014
Feb 2014
Mar 2014
Apr 2014
May 2014
Jun 2014
Jul 2014
Aug 2014
Sep 2014
Oct 2014
Nov 2014
Dec 2014
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Forecast)

Combined KU and LG&E ROE (TTM) March 2014

KU and LG&E Combined

Reconciliation of Allowed Return to

3/31/14 Trailing Twelve Months Regulatory Return and

Book ROE from Ongoing Operations

Allowed Return [1]			10.32%	
Adjustments (net of tax):				
	Change in capitalization - non ECR	-1.06%		Growth in non-ECR capitalization (rate base) between rate cases does not earn a return
	Change in ROE from average mechanism rate base gr	0.00%		Mechanisms have a real-time return
	Change in weighted cost of debt	-0.12%		Additional borrowings offset by favorable rates
	Change in margins	1.89%		Primarily new rates since last rate cases
	Change in allowed expenses	-0.58%		Inflationary increases
			0.14%	
Actual Regulated ROE			10.45%	
Adjustments (net of tax):				
	Impact of non-recoverable purchase accounting	-2.00%		
	Impact of 'below the line' items not recoverable through rates	-0.09%		
			-2.09%	
Actual Book ROE from Ongoing Operations			8.36%	

[1] Based on the most recent base rate filings with test years ending 3/31/12 KPSC, 12/31/12 FERC, 12/31/12 VA.

Performance Report

April 2014

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Kentucky Regulated Dashboard April 2014

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.11	1.23	1.30	1.19	1.30	1.29
Employee lost-time incidents	0	0	2	0	2	3
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,334	2,390	11,783	11,075	35,487	34,780
Utility EFOR	8.1%	5.9%	3.7%	5.9%	N/A	5.9%
Utility EAF	55.4%	59.5%	77.2%	75.5%	N/A	82.5%
Steam Fleet Commercial Availability	92.0%	91.5%	96.7%	91.5%	N/A	91.5%
Combined SAIFI	0.06	0.11	0.28	0.31	N/A	1.20
Combined SAIDI (minutes)	6.04	9.94	25.74	29.58	N/A	107.60
GwH Sales						
Residential	596	718	4,016	3,750	11,349	10,962
Commercial	571	569	2,560	2,427	8,083	7,952
Industrial	818	755	3,188	3,055	10,082	10,011
Municipals	128	146	640	634	1,993	1,969
Other	209	205	925	859	2,850	2,788
Off-System Sales	1	0	219	108	345	273
Total	2,323	2,392	11,548	10,831	34,702	33,954
Weather-Normalized Sales Growth			**TTM**			
Residential			-1.17%			
Commercial			-1.35%			
Industrial			1.46%			
Municipal			-2.59%			
Other			-0.65%			
Total			-0.49%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[(1)]	3.4%	4.5%	10.3%	8.7%	9.1%	8.7%
Electric Margins	$118	$121	$566	$532	$1,689	$1,664
Gas Margins	11	11	70	69	157	157
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$10	$12	$47	$59	$117	$126
ECR	$64	$48	$190	$186	$618	$603
Generation	$10	$6	$22	$29	$115	$121
Transmission	$9	$8	$28	$28	$85	$77
Electric Distribution	$10	$13	$36	$42	$148	$143
Gas Distribution	$5	$6	$17	$22	$83	$80
Customer Services	$1	$2	$4	$6	$18	$20
IT and Other	$3	$4	$11	$17	$45	$50
Total	$112	$99	$354	$388	$1,228	$1,221
O&M ($ millions)[(2)]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$50	$44	$167	$158	$481	$468
Administrative	8	8	31	32	98	98
Finance	1	2	6	7	19	19
Burdens & Other Charges	11	12	49	50	144	150
Total	$70	$66	$253	$247	$742	$735
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,440	3,544	3,440	3,544	3,546	3,549
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	3	0	6	3	N/A	14
NERC Possible Violations	0	3	0	3	N/A	11

Variance Explanations

- MTD EFOR below budget due to first reheater pluggage at Cane Run 4 and a lost feed from the switchyard at Cane Run 6. MTD EAF was affected by Cane Run 6 scrubber repairs and a boiler ashpit cleaning.

- YTD generation volumes and GWh sales were impacted by cold weather. Generation volumes were also impacted by excellent plant availability.

- YTD higher margins driven by unusually cold weather and system availability, including $21 million from retail electric energy and demand charge revenues, $8 million from excess generation sold at market prices and $6 million from higher gas margins, higher transmission revenue and other retail mechanisms.

- MTD capital was $13 million higher than budget MTD due primarily to spending on Mill Creek environmental air projects due to delays in 2013.

- YTD capital was $34 million lower than budget due primarily to timing of spending on Cane Run Unit 7 and milestone shifts on Ghent environmental air projects, partially offset by higher than budgeted spending on Mill Creek environmental air projects due to delays in 2013.

- YTD higher O&M primarily due to $7 million of higher storm expenses and $2 million higher uncollectible accounts, partially offset by $3 million of labor savings.

- O&M full year forecast $7 million higher, due primarily to the impacts of the cold winter (bad debt expense, storms expense and plant maintenance), partially offset by labor savings.

Major Developments

- The KPSC issued an Order granting LG&E and KU's motion to hold the Green River 5 CPCN proceeding in abeyance for up to 90 days. LG&E and KU are currently assessing the potential impact of recent events on its future capacity needs, including the receipt of five-year termination notices from certain KU municipal wholesale customers totaling approximately 300 megawatts. LG&E and KU continue to meet with the respective municipals.

- LG&E and KU filed its Integrated Resource Plan which is required by the KPSC every three years. Key findings presented in the filing include: using DSM programs to reduce peak demand by 500 MWs by the end of 2018, the retirements of three coal-fired plants (Cane Run, Green River, and Tyrone), and the continuation of a 16 percent target reserve margin.

Significant Future Events

- The KPSC cancelled a July 8 hearing associated with the Green River 5 CPCN and scheduled an informal conference for August 7.

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(1) Excludes goodwill and other purchase accounting adjustments.
(2) Net of cost recovery mechanisms.

Income Statement: Actual vs. Budget and Forecast (Month) April 2014

($ Millions)

	MTD				MTD			
	Actual	Budget	Variance	Comments	Actual	Q1 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 204	$ 204	$ (0)		$ 204	$ 204	$ (0)	
Gas Revenues	22	20	2		22	20	1	
Total Revenues	225	224	1		225	224	1	
Cost of Sales:								
Fuel Electric Costs	72	68	(4)		72	68	(4)	
Gas Supply Expenses	11	9	(1)		11	9	(1)	
Purchased Power	6	7	1		6	7	1	
Other Electric Cost	8	8	0		8	8	0	
Total Cost of Sales	96	92	(4)		96	92	(4)	
Gross Margin:								
Electric Margin	118	121	(3)		118	121	(3)	
Gas Margin	11	11	0		11	11	0	
Total Gross Margin	129	132	(3)		129	132	(3)	
Operating Expenses:								
O&M	70	66	(4)		70	69	(0)	
Depreciation & Amortization	28	29	0		28	29	0	
Taxes, Other than Income	4	4	0		4	4	0	
Total Operating Expenses	102	99	(3)		102	102	(0)	
Other income	(2)	(1)	(0)		(2)	(2)	(0)	
EBIT	26	32	(6)		26	29	(3)	
Interest Expense	14	14	0		14	14	0	
Income from Ongoing Operations before income taxes	12	18	(6)		12	14	(2)	
Income Tax Expense	4	6	2		4	5	1	
Net Income (loss) from ongoing operations	**$ 7**	**$ 11**	**$ (4)**		**$ 8**	**$ 9**	**$ (2)**	
Non Operating Income	0	0	0		0	0	0	
Discontinued Operations	0	0	(0)		0	0	(0)	
Net Income (loss)	$ 7	$ 11	$ (4)		$ 7	$ 9	$ (2)	
KY Regulated Financing Costs	(3)	(3)	(0)		(3)	(3)	(0)	
KY Regulated Net Income	$ 5	$ 9	$ (4)		$ 5	$ 7	$ (2)	
Earnings Per Share	$ 0.01	$ 0.01	$ (0.01)		$ 0.01	$ 0.01	$ (0.01)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) and Forecast vs. Budget (Full Year) April 2014

($ Millions)

	YTD				Full Year			
	Actual	**Budget**	**Variance**	**Comments**	**FY Forecast**	**Budget**	**Variance**	**Comments**
Revenues:								
Electric Revenues	$ 970	$ 894	$ 75	Due to increasing electricty volumes resulting from colder than normal weather.	$ 2,876	$ 2,815	$ 60	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Revenues	190	156	34	Due to increasing gas volumes resulting from colder than normal weather.	351	318	33	Due to increasing gas volumes resulting from colder than normal weather.
Total Revenues	1,160	1,051	109		3,227	3,134	93	
Cost of Sales:								
Fuel Electric Costs	351	303	(48)	Due to increasing electricty volumes resulting from colder than normal weather.	1,000	953	(47)	Due to increasing electricty volumes resulting from colder than normal weather.
Gas Supply Expenses	120	87	(33)	Due to increasing gas volumes resulting from colder than normal weather.	194	162	(33)	Due to increasing gas volumes resulting from colder than normal weather.
Purchased Power	20	25	4		68	72	4	
Other Electric Cost	32	35	3		123	127	4	
Total Cost of Sales	523	449	(74)		1,385	1,313	(72)	
Gross Margin:								
Electric Margin	566	532	34	Higher margins driven by favorable weather and system availability.	1,689	1,664	25	Higher margins driven by favorable weather and system availability.
Gas Margin	70	69	1		157	157	(0)	
Total Gross Margin	636	601	35		1,846	1,820	25	
Operating Expenses:								
O&M	253	247	(6)	Due primarily to weather related expenses, partially offset by lower labor related costs.	742	735	(7)	Due primarily to weather related expenses, partially offset by lower labor related costs.
Depreciation & Amortization	113	114	1		342	344	1	
Taxes, Other than Income	17	17	0		51	51	0	
Total Operating Expenses	382	378	(5)		1,136	1,130	(6)	
Other income	(4)	(4)	0		(6)	(7)	1	
EBIT	250	220	31		704	684	20	
Interest Expense	56	57	2		171	172	2	
Income from Ongoing Operations before income taxes	195	163	32		533	511	22	
Income Tax Expense	73	61	(12)	Higher pre-tax income.	200	192	(7)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**$ 121**	**$ 101**	**$ 20**		**$ 333**	**$ 319**	**13**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	(0)	0	(0)		0	0	(0)	
Net Income (loss)	$ 122	$ 102	$ 20		$ 333	$ 320	$ 13	
KY Regulated Financing Costs	(10)	(10)	(0)		(31)	(31)	0	
KY Regulated Net Income	$ 111	$ 91	$ 20		$ 302	$ 288	$ 14	
Earnings Per Share	$ 0.17	$ 0.14	$ 0.03		$ 0.45	$ 0.43	$ 0.02	

Note: Schedules may not sum due to rounding.

Electric Gross Margin

April 2014

($ Millions)

	MTD						YTD					
	Actual	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**	**Actual**	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**
Base Electric Margin:						◆ $ (4)						● $ 21
Energy Volumes (a)	2,322,216	2,392,476	(70,259)	$ -	$ (5)		11,329,452	10,723,560	605,892	$ -	$ 20	
Energy Prices (a)					(1)						(4)	
Customer Charges (Avg. Customers)	938,790	946,628	(7,838)		1		939,982	945,193	(5,211)		0	
Demand Charges (b)	38	36			1		151	146			5	
ECR:						● $ 0						◆ $ (1)
Average Rate Base	$ 1,277	$ 1,249	$ 28	10.37%	$ 0.2		$ 1,197	$ 1,185	$ 12	10.39%	$ 0.4	
Cost of Capital	10.22%	10.37%	-0.15%	$ 1,277	$ (0.1)		10.21%	10.39%	-0.18%	$ 1,197	(0.6)	
Jurisdictional Factor	87.64%	88.31%	-0.67%	$ 1,277	$ (0.1)		85.82%	86.90%	-1.08%	$ 1,197	(0.4)	
Other					$ 0.3						(0.1)	
DSM:						◆ $ (1)						◆ $ (3)
Program Expense (Revenue Net of Expense)	$ -	$ -			$ -		$ (0.1)	$ 0.1			$ (0.2)	
Lost Sales	1.5	1.9			$ (0.4)		5.4	7.4			(2.0)	
Incentive	0.1	0.1			$ -		0.3	0.3			-	
Balancing Adjustment	(0.5)	-			$ (0.5)		(0.3)	-			(0.3)	
Net Fuel Recovery	$ -	$ (0.4)				● $ 0	$ (3)	$ (2)				◆ $ (2)
Purchase Power Demand	(2.5)	(2.5)				● $ -	(8.4)	(10.1)				● $ 2
Transmission	0.1	0.5				◆ $ (0)	3.9	3.0				● $ 1
Other	(0.6)	(2.1)				● $ 2	(4.8)	(12.1)				● $ 7
Retail Margin Variance						◆ $ (3)						● $ 26
Off-System Margin Variance						● $ -						● $ 8
Electric Margin Variance						◆ $ (3)						● $ 34

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 29	595,774	$ 48.91	$ 35	718,299	$ 48.82	◆ ($6)	◆ ($6)	● $0
Commercial	17	570,886	30.43	18	568,963	31.90	◆ ($1)	● $0	◆ ($1)
Industrial	7	818,068	8.94	7	754,972	8.92	● $1	● $1	● $0
Municipals	1	128,374	5.56	1	145,556	5.56	◆ ($0)	◆ ($0)	● $0
Other	5	209,114	23.82	5	204,685	23.61	● $0	● $0	● $0
Native Load Total	**$ 60**	**2,322,216**	**$ 25.63**	**$ 66**	**2,392,476**	**$ 27.42**	◆ **($6)**	◆ **($5)**	◆ **($1)**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 194	4,015,430	$ 48.39	$ 182	3,750,436	$ 48.59	● $12	● $13	◆ ($1)
Commercial	81	2,559,795	31.52	80	2,426,601	32.75	● $1	● $4	◆ ($3)
Industrial	29	3,188,273	8.95	27	3,054,547	8.97	● $1	● $1	● $0
Municipals	4	640,618	5.56	4	633,659	5.56	● $0	● $0	● $0
Other	22	925,335	23.99	21	858,317	23.93	● $2	● $2	● $0
Native Load Total	**$ 329**	**11,329,452**	**$ 29.07**	**$ 313**	**10,723,560**	**$ 29.20**	● **$16**	● **$20**	◆ **($4)**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD			YTD		
	Act	**Bud**	**Variance**	**Act**	**Bud**	**Variance**
Commercial	13	11	2	51	46	5
Industrial	16	16	(0)	62	63	(1)
Municipals	3	4	(1)	17	17	0
Other	5	5	0	21	20	1
Native Load Total	**38**	**36**	**1**	**151**	**146**	**5**

Gas Gross Margin April 2014

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	$ 5	$ 5		🟢 $ -	$ 20	$ 20		🟢 $ 0
Gas Supply Costs								
Gas Supply Costs	(11)	(9)	$ (2)		(119)	(87)	$ (32)	
GSC Revenue	10	9	1		118	87	31	
Net Gas Supply Costs				♦ $ (0)				♦ $ (1)
Retail Gas (a)	5	5		♦ $ (0)	54	46		🟢 $ 8
Wholesale Gas (a)	-	-		🟢 $ -	-	-		🟢 $ -
DSM	-	0		♦ $ (0)	0	0		🟢 $ -
GLT	1	1		♦ $ (0)	2	3		♦ $ (1)
WNA	1	-		🟢 $ 1	(6)	-		♦ $ (6)
Other Margin	0	0		🟢 $ 0	1	1		🟢 $ 0
Gas Margin Variance				🟢 $ 0				🟢 $ 1

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 3	1,022,242	$ 2.64	$ 3	1,074,826	$ 2.64	♦ ($0)	♦ $ (0)	🟢 $ -
Commercial	1	534,608	1.92	1	483,985	2.08	🟢 $0	🟢 $ 0	♦ $ (0)
Industrial	0	73,744	1.80	0	70,385	1.80	🟢 $0	🟢 $ -	🟢 $ -
Public Authority	0	79,793	1.80	0	102,056	2.01	♦ ($0)	🟢 $ -	🟢 $ -
Transportation	1	1,577,341	0.60	0.80	901,612	0.89	🟢 $0	🟢 $ 1	♦ $ (1)
Ultimate Consumer	$ 5	3,287,728	$ 1.50	$ 5	2,632,865	$ 1.89	♦ ($0)	🟢 $ 1	♦ $ (1)

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 34	13,029,660	$ 2.64	$ 30	11,184,078	$ 2.64	🟢 $5	🟢 $ 5	🟢 $ -
Commercial	12	5,811,682	2.06	10	4,724,736	2.08	🟢 $2	🟢 $ 2	♦ $ (0)
Industrial	1	528,000	1.97	1	439,563	1.80	🟢 $0	🟢 $ 0	🟢 $ 0
Public Authority	2	926,793	2.02	2	838,836	2.02	🟢 $0	🟢 $ 0	🟢 $ -
Transportation	4	5,795,797	0.75	4	4,970,881	0.76	🟢 $1	🟢 $ 1	♦ $ (0)
Ultimate Consumer	$ 54	26,091,932	$ 2.06	$ 46	22,158,093	$ 2.06	🟢 $8	🟢 $ 8	♦ $ (0)

O&M **April 2014**

($ Millions)

	MTD								
	Actual	**Budget**	**Total Variance**	**Labor**	**Outages**	**Outside Services**	**Materials**	**Uncollectible Accounts**	**Other**
Generation	$ 29	$ 26	$ (3)	$ 1	$ (3)	$ (1)	$ (0)		$ (0)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	2	2	0	(0)		0	0		(0)
Energy Supply and Analysis	1	1	0	(0)		0	(0)		0
Electric Distribution	8	6	(2)	0		(2)	(0)	(0)	(0)
Gas Distribution	3	3	0	0		0	0	(0)	(0)
Safety and Security	0	0	(0)	(0)		(0)	0	0	(0)
Customer Services	7	6	(1)	(0)		(0)	0	(0)	(0)
Chief Operations Officer	**50**	**44**	**(5)**	**1**	**(3)**	**(3)**	**(0)**	**(0)**	**(1)**
Information Technology	4	4	0	0		0	(0)		(0)
General Counsel	2	2	0	0		0	0		(0)
Human Resources	1	1	0	0		(0)	0		0
Supply Chain	0	0	0	0		0	(0)		0
Chief Administrative Officer	**8**	**8**	**0**	**0**		**0**	**(0)**		**(0)**
Chief Financial Officer	**1**	**2**	**0**	**0**		**0**	**0**		**0**
Corporate	**11**	**12**	**1**	**0**		**1**	**0**		**0**
O&M Total MTD	**$ 70**	**$ 66**	**$ (4)**	**$ 2**	**$ (3)**	**$ (2)**	**$ 0**	**$ (0)**	**$ (1)**

	YTD								
	Actual	**Budget**	**Total Variance**	**Labor**	**Outages**	**Outside Services**	**Materials**	**Uncollectible Accounts**	**Other**
Generation	$ 86	$ 86	$ 0	$ 2	$ 3	$ (2)	$ (1)		$ (1)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	9	9	0	(0)		0	0		(0)
Energy Supply and Analysis	3	3	0	0		0	0		0
Electric Distribution	29	24	(5)	(0)		(4)	(0)	(0)	(0)
Gas Distribution	11	10	(1)	(0)		0	(0)	(0)	(1)
Safety and Security	1	0	(1)	(1)		(0)	0	0	(0)
Customer Services	28	25	(3)	0		(1)	0	(2)	(0)
Chief Operations Officer	**167**	**158**	**(9)**	**1**	**3**	**(7)**	**(1)**	**(2)**	**(2)**
Information Technology	17	18	1	1		0	(0)		(0)
General Counsel	10	10	0	0		0	0		(0)
Human Resources	2	3	0	(0)		(0)	0		0
Supply Chain	1	1	0	0		(0)	(0)		0
Chief Administrative Officer	**31**	**32**	**2**	**1**		**0**	**(0)**		**0**
Chief Financial Officer	**6**	**7**	**0**	**0**		**0**	**0**		**0**
Corporate	**49**	**50**	**1**	**2**		**1**	**1**		**(3)**
O&M Total YTD	**$ 253**	**$ 247**	**$ (6)**	**$ 5**	**$ 3**	**$ (6)**	**$ (1)**	**$ (2)**	**$ (5)**

	Full Year								
	Forecast	**Budget**	**Total Variance**	**Labor**	**Outages**	**Outside Services**	**Materials**	**Uncollectible Accounts**	**Other**
Generation	$ 246	$ 245	$ (0)	$ 3	$ (0)	$ (3)	$ 1		$ (1)
Project Engineering	1	1	0	(0)		(0)	(0)		0
Transmission	29	29	(1)	(0)		(0)	(0)		(0)
Energy Supply and Analysis	9	9	0	0		0	0		0
Electric Distribution	74	72	(1)	2		(3)	0	0	(0)
Gas Distribution	32	32	(0)	(0)		(0)	0	0	(0)
Safety and Security	3	0	(3)	(3)		(0)	(0)	0	0
Customer Services	87	79	(8)	(0)		(3)	0	(4)	(0)
Chief Operations Officer	**481**	**468**	**(13)**	**2**	**(0)**	**(10)**	**1**	**(4)**	**(2)**
Information Technology	55	55	0	1		(0)	(0)		(0)
General Counsel	32	32	0	0		0	0		0
Human Resources	8	8	0	0		0	0		0
Supply Chain	4	4	0	0		0	0		0
Chief Administrative Officer	**98**	**98**	**0**	**1**		**0**	**(0)**		**(0)**
Chief Financial Officer	**19**	**19**	**0**	**0**		**0**	**0**		**(0)**
Corporate	**144**	**150**	**6**	**7**		**(0)**	**(0)**	**0**	**(1)**
O&M Total Full Year	**$ 742**	**$ 735**	**$ (7)**	**$ 9**	**$ (0)**	**$ (10)**	**$ 1**	**$ (4)**	**$ (3)**

Note: Schedules may not sum due to rounding.

Financing Activities April 2014

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB									
Beg Bal	$ 924.0	$ 924.4	$ 0.4	$ 924.0	$ 924.0	$ 0.0	$ 924.0	$ 924.0	$ -
End Bal	924.0	924.4	0.4	924.0	924.4	0.4	926.0	924.9	(1.1)
Ave Bal	**$ 924.0**	**$ 924.4**	**$ 0.4**	**$ 924.0**	**$ 924.3**	**$ 0.3**	**$ 924.7**	**$ 924.6**	**$ (0.2)**
Interest Exp	**$ 0.8**	**$ 0.9**	**$ 0.2**	**$ 3.0**	**$ 3.8**	**$ 0.7**	**$ 10.8**	**$ 11.3**	**$ 0.6**
Rate	**1.00%**	**1.23%**	**0.23%**	**0.99%**	**1.23%**	**0.24%**	**1.17%**	**1.23%**	**0.06%**
FMB/Sr Nts									
Beg Bal	$ 3,641.3	$ 3,641.3	$ (0.0)	$ 3,640.9	$ 3,640.9	$ -	$ 3,640.9	$ 3,640.9	$ -
End Bal	3,641.5	3,641.4	(0.0)	3,641.5	3,641.4	(0.0)	3,642.6	3,642.5	(0.0)
Ave Bal	**$ 3,641.4**	**$ 3,641.4**	**$ (0.0)**	**$ 3,641.2**	**$ 3,641.2**	**$ 0.1**	**$ 3,641.8**	**$ 3,641.8**	**$ (0.0)**
Interest Exp	**$ 11.5**	**$ 11.6**	**$ 0.1**	**$ 46.0**	**$ 46.6**	**$ 0.6**	**$ 140.9**	**$ 141.4**	**$ 0.4**
Rate	**3.79%**	**3.84%**	**0.05%**	**3.79%**	**3.84%**	**0.05%**	**3.87%**	**3.88%**	**0.01%**
Short-term Debt									
Beg Bal	$ 200.0	$ 265.8	$ 65.9	$ 245.0	$ 245.0	$ -	$ 245.0	$ 245.0	$ -
End Bal	177.0	247.9	70.9	177.0	247.9	70.9	543.4	527.8	(15.6)
Ave Bal	**$ 188.5**	**$ 256.9**	**$ 68.4**	**$ 211.0**	**$ 235.7**	**$ 24.7**	**$ 368.1**	**$ 356.8**	**$ (11.3)**
Interest Exp	**$ 0.1**	**$ 0.4**	**$ 0.3**	**$ 0.7**	**$ 1.4**	**$ 0.8**	**$ 3.4**	**$ 3.6**	**$ 0.2**
Rate	**0.35%**	**1.74%**	**1.40%**	**0.94%**	**1.83%**	**0.90%**	**0.91%**	**1.00%**	**0.09%**
Total End Bal	**$ 4,742.4**	**$ 4,813.7**	**$ 71.2**	**$ 4,742.4**	**$ 4,813.7**	**$ 71.2**	**$ 5,112.0**	**$ 5,095.3**	**$ (16.7)**
Total Average Bal	**$ 4,753.8**	**$ 4,822.6**	**$ 68.7**	**$ 4,776.1**	**$ 4,801.2**	**$ 25.1**	**$ 4,934.7**	**$ 4,923.2**	**$ (11.5)**
Total Expense Excl I/C	**$ 13.9**	**$ 14.3**	**$ 0.4**	**$ 55.6**	**$ 57.3**	**$ 1.7**	**$ 171.2**	**$ 172.4**	**$ 1.2**
Rate	**3.51%**	**3.57%**	**0.06%**	**3.49%**	**3.58%**	**0.09%**	**3.47%**	**3.50%**	**0.03%**

Credit Facilities ($ Millions)	**Committed Capacity**	**Borrowed**	**Letters of Credit Issued**	**Unused Capacity**
LKE	$ 300	$ 75		$ 225
LG&E	500	20		480
KU	598	82	$ 198	318
TOTAL	$ 1,398	$ 177	$ 198	$ 1,023

Credit Metrics ($ Millions)	**YTD Actual**	**YTD +/- Bud**	**Full Year Forecast**	**Full Year +/- Bud**
FFO to Debt - LG&E	29.3%	+0.00	21.6%	-0.01
FFO to Debt - KU	26.8%	+0.01	22.7%	-0.01
Debt to EBITDA - LG&E (1)	3.03	-0.64	3.59	-0.07
Debt to EBITDA - KU (1)	3.47	-0.26	3.67	-0.05
Debt to Capitalization - LG&E (2)	46.9%	+0.02	47.0%	-0.00
Debt to Capitalization - KU (2)	46.8%	-0.01	47.0%	-0.00

(1) Actuals represent a trailing 12 months

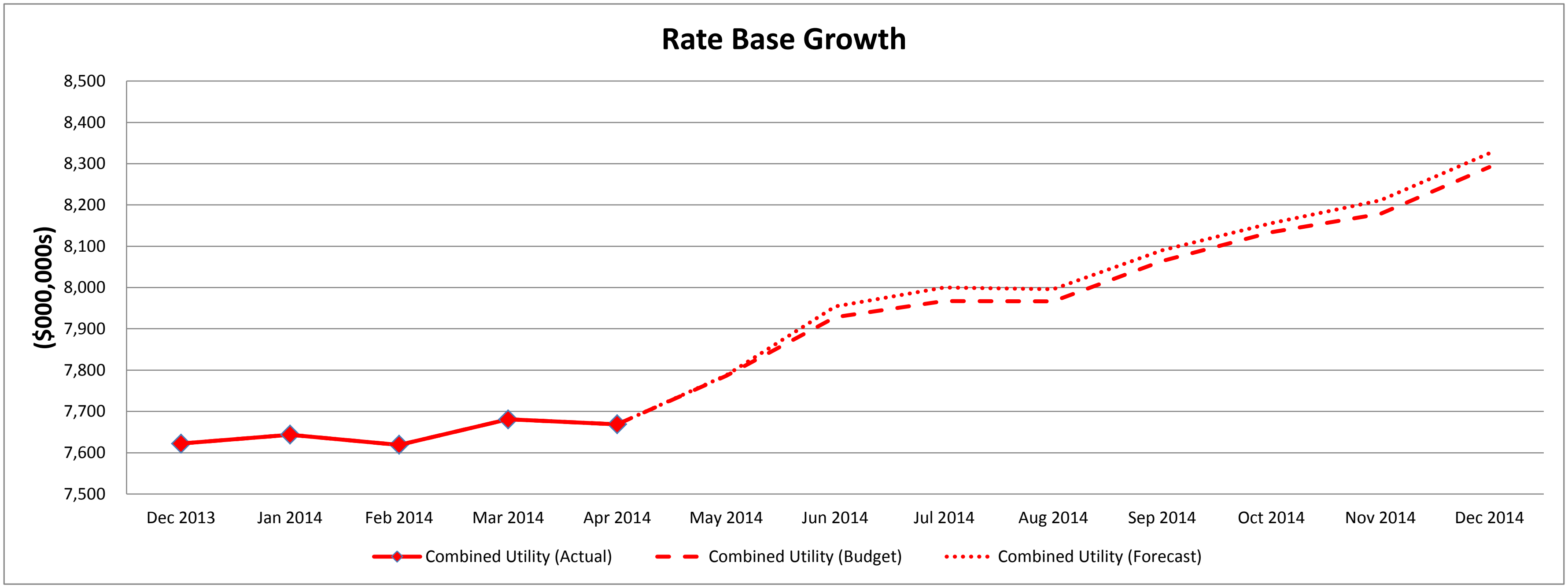
(2) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet — April 2014

($ Millions)

	4/30/2014	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 17	$ 9	$ 8	
Accounts Receivable (Trade)	364	389	(24)	Lower unbilled utility revenue ($51m) off set by higher customer accounts receivable ($30m).
Inventory	237	235	3	
Deferred Income Taxes	139	159	(20)	Deferred Income Taxes reclassified from asset to liability Deferred Tax Liabilities.
Prepayments and other current assets	71	115	(45)	Lower notes receivable from affiliate ($37m).
Total Current Assets	828	907	(78)	
Property, Plant, and Equipment	9,786	9,819	(33)	Lower Electric Plant In Service ($86m) and CWIP ($25m) partially offet by higher completed construction electric ($68m).
Intangible Assets	205	205	(0)	
Other Property and Investments	1	1	(0)	
Regulatory Assets	511	496	15	Higher GSC revenue ($14m).
Goodwill	997	997	0	
Other Long-term Assets	95	95	0	
Total Assets	**$ 12,422**	**$ 12,520**	**$ (97)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 368	$ 335	$ 34	Primarily due to higher fuel volumes.
Accounts Payable - Affiliated Company	0	0	0	
Customer Deposits	50	50	1	
Derivative Liability	4	4	0	
Accrued Taxes	45	56	(11)	Higher pre-tax income.
Other Current Liabilities	175	161	14	Mostly due to $17m in payments on the last business day of the month out the A/P account which didn't have time to be funded from the Funding Account, creating negative cash in the A/P account and a liability in the credit cash adjustment account.
Total Current Liabilities	643	605	38	
Debt - Affiliated Company	-	7	(7)	
Debt [(1)]	4,742	4,807	(64)	Lower issuance of Commercial Paper ($64m) due to lower pension and capex payments.
Total Debt	4,742	4,814	(71)	
Deferred Tax Liabilities	1,019	1,041	(22)	Deferred Tax Liabilities reclassified from liability to asset as Deferred Income Taxes.
Investment Tax Credit	133	133	(0)	
Accum Provision for Pension & Related Benefits	120	119	1	
Asset Retirement Obligation	252	247	5	
Regulatory Liabilities	1,029	1,034	(5)	
Derivative Liability	37	32	5	
Other Liabilities	240	237	3	
Total Deferred Credits and Other Liabilities	2,830	2,844	(14)	
Equity	4,207	4,257	(50)	
Total Liabilities and Equity	**$ 12,422**	**$ 12,520**	**$ (97)**	

(1) Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.


Rate Base Growth
($000,000s)
8,500
8,400
8,300
8,200
8,100
8,000
7,900
7,800
7,700
7,600
7,500
Dec 2013
Jan 2014
Feb 2014
Mar 2014
Apr 2014
May 2014
Jun 2014
Jul 2014
Aug 2014
Sep 2014
Oct 2014
Nov 2014
Dec 2014
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Forecast)

Performance Report

May 2014

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Kentucky Regulated Dashboard

May 2014

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.55	0.57	1.11	1.03	1.11	1.29
Employee lost-time incidents	0	0	2	0	2	3
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,732	2,691	14,515	13,767	35,558	34,780
Utility EFOR	4.0%	5.9%	3.8%	5.9%	N/A	5.9%
Utility EAF	77.9%	83.3%	77.2%	77.1%	N/A	82.5%
Steam Fleet Commercial Availability	86.8%	91.5%	94.8%	91.5%	N/A	91.5%
Combined SAIFI	0.13	0.12	0.41	0.43	N/A	1.20
Combined SAIDI (minutes)	11.75	10.54	37.48	40.11	N/A	107.60
GwH Sales						
Residential	748	674	4,763	4,424	11,349	10,962
Commercial	634	642	3,194	3,069	8,083	7,952
Industrial	858	877	4,046	3,931	10,082	10,011
Municipals	146	151	787	784	1,993	1,969
Other	232	235	1,157	1,093	2,850	2,788
Off-System Sales	44	65	263	174	345	273
Total	2,662	2,644	14,211	13,475	34,702	33,954
Weather-Normalized Sales Growth			**TTM**			
Residential			-1.72%			
Commercial			-1.27%			
Industrial			1.58%			
Municipal			-1.45%			
Other			-0.10%			
Total			-0.50%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE(1)	8.3%	6.3%	9.9%	8.2%	9.1%	8.7%
Electric Margins	$134	$127	$701	$659	$1,689	$1,664
Gas Margins	9	9	79	78	157	157
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$12	$13	$59	$72	$119	$126
ECR	$66	$62	$256	$248	$622	$603
Generation	$6	$7	$27	$36	$115	$121
Transmission	$7	$6	$35	$34	$84	$77
Electric Distribution	$11	$13	$48	$55	$149	$143
Gas Distribution	$7	$8	$24	$30	$82	$80
Customer Services	$2	$2	$5	$8	$18	$20
IT and Other	$2	$4	$13	$21	$40	$50
Total	$113	$115	$467	$503	$1,229	$1,221
O&M ($ millions)(2)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$38	$37	$205	$195	$481	$468
Administrative	8	8	$38	40	98	98
Finance	2	2	$8	8	19	19
Burdens & Other Charges	8	12	$57	63	144	150
Total	$56	$60	$308	$306	$742	$735
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,450	3,547	3,450	3,547	3,546	3,549
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	0	6	3	N/A	14
NERC Possible Violations	1	0	1	3	N/A	11

Variance Explanations

- YTD generation volumes and GWh sales were impacted by favorable weather. Generation volumes were also impacted by excellent plant availability.
- MTD higher margins mostly driven by warmer weather, including $5 million from retail electric energy and demand charge revenues.
- YTD higher margins driven by favorable weather and system availability, including $26 million from retail electric energy and demand charge revenues, $9 million from excess generation sold at market prices and $8 million from higher gas margins, higher transmission revenue and other retail mechanisms.
- YTD capital was $36m lower than budget YTD due primarily to timing of spending on Cane Run Unit 7, the Ohio Falls rehabilitation project, circuit hardening and gas service risers, as well as milestone shifts on Ghent environmental air projects; partially offset by higher than budgeted spending on Mill Creek environmental air projects due to delays in 2013.
- MTD lower O&M due to $4 million of labor and benefit savings.
- YTD higher O&M primarily due to $8 million of higher storm expenses and $2 million of higher uncollectible accounts, partially offset by $7 million of labor and benefit savings.
- O&M full year forecast $7 million higher, due primarily to the impacts of the cold winter (bad debt expense, storms expense and plant maintenance), partially offset by labor savings.

Major Developments

- LKE was recently honored with multiple awards from external organizations covering a variety of disciplines. LKE's health and safety initiatives continue to flourish as LKE earned the Louisville Mayor's Healthy Hometown Award and five safety awards including two prestigious Kentucky Governor's Safety and Health Awards for Project Engineering and E.W. Brown. In addition to LKE's health and safety achievements, LKE has also been recognized for its efforts in support of employee commitment, supplier diversity and information technology. LKE's Strategic Business Integration program was one of two utilities worldwide who received an "Excellence in Practice" citation from the Association for Talent Development. LKE also garnered the 2014 EEI Supplier Diversity Excellence Award for working with 140 diverse businesses in 2013 with a total spend of approximately $133 million. Lastly, LKE was named a recipient of the 2014 CIO 100 by CIO magazine, for the deployment of a one-of-a-kind iPad application allowing the Aerial Patrol group to capture transmission data easily without having to manually download data into a computer.
- KU achieved a major milestone as the first fabric filter constructed at Ghent on Unit 3 was successfully placed in service and operating at full load.
- As previously referenced in the March report, the Sierra Club, along with the nonprofit environmental law organization Earthjustice, pursued its intent to sue LG&E and formally filed a federal lawsuit alleging violation of the Clean Water Act at LG&E's Mill Creek plant.
- Metro Council passed a natural gas franchise ordinance authorizing Louisville Metro Government to bid a gas franchise agreement for sixteen months and with a franchise fee of 2 percent of gross receipts. The 2 percent franchise fee will generate $3.8 million and will be utilized to improve public safety. The franchise fees represent pass-through charges and are shown as a separate line item on the bill including the name of the city assessing the charge.

Significant Future Events

- An informal conference related to the Green River 5 CPCN is scheduled for August 7.

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(1) Excludes goodwill and other purchase accounting adjustments.
(2) Net of cost recovery mechanisms.

Income Statement: Actual vs. Budget and Forecast (Month)

May 2014

($ Millions)

	MTD				MTD			
	Actual	**Budget**	**Variance**	**Comments**	**Actual**	**Q1 Forecast**	**Variance**	**Comments**
Revenues:								
Electric Revenues	$ 224	$ 214	$ 10	Due to increasing electricty volumes resulting from warmer than normal weather.	$ 224	$ 212	$ 12	Due to increasing electricty volumes resulting from warmer than normal weather.
Gas Revenues	16	15	0		16	15	0	
Total Revenues	240	229	11		240	227	12	
Cost of Sales:								
Fuel Electric Costs	78	72	(6)	Due to increasing electricty volumes resulting from warmer than normal weather.	78	71	(7)	Due to increasing electricty volumes resulting from warmer than normal weather.
Gas Supply Expenses	7	6	(1)		7	6	(1)	
Purchased Power	4	5	1		4	5	1	
Other Electric Cost	8	10	2		8	10	2	
Total Cost of Sales	97	93	(3)		97	92	(5)	
Gross Margin:								
Electric Margin	134	127	7	Higher margins driven by favorable weather and system availability.	134	126	8	Higher margins driven by favorable weather and system availability.
Gas Margin	9	9	(0)		9	9	(0)	
Total Gross Margin	143	136	7		143	135	8	
Operating Expenses:								
O&M	56	60	4		56	60	4	
Depreciation & Amortization	28	29	0		28	29	0	
Taxes, Other than Income	4	4	0		4	4	0	
Total Operating Expenses	88	92	4		88	93	5	
Other income	(0)	(0)	0		(0)	(0)	0	
EBIT	54	43	12		54	42	12	
Interest Expense	14	14	0		14	14	0	
Income from Ongoing Operations before income taxes	40	28	12		40	28	13	
Income Tax Expense	15	10	(5)	Higher due to higher pre-tax income.	15	10	(5)	Higher due to higher pre-tax income.
Net Income (loss) from ongoing operations	**$ 25**	**$ 18**	**$ 7**		**$ 25**	**18**	**$ 8**	
Non Operating Income	0	0	0		0	0	0	
Discontinued Operations	0	0	(0)		0	0	(0)	
Net Income (loss)	$ 25	$ 18	$ 7		$ 25	$ 18	$ 8	
KY Regulated Financing Costs	(3)	(3)	(0)		(3)	(3)	(0)	
KY Regulated Net Income	$ 23	$ 15	$ 7		$ 23	$ 15	$ 8	
Earnings Per Share	$ 0.03	$ 0.02	$ 0.01		$ 0.03	$ 0.02	$ 0.01	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) and Forecast vs. Budget (Full Year) May 2014

($ Millions)

	YTD				Full Year			
	Actual	Budget	Variance	Comments	FY Forecast	Budget	Variance	Comments
Revenues:								
Electric Revenues	$ 1,194	$ 1,108	$ 86	Due to increasing electricty volumes resulting from favorable weather.	$ 2,883	$ 2,815	$ 67	Due to increasing electricty volumes resulting from favorable weather.
Gas Revenues	206	172	34	Due to increasing gas volumes resulting from colder than normal weather.	352	318	34	Due to increasing gas volumes resulting from colder than normal weather.
Total Revenues	1,400	1,280	120		3,235	3,134	101	
Cost of Sales:								
Fuel Electric Costs	429	375	(54)	Due to increasing electricty volumes resulting from favorable weather.	1,007	953	(54)	Due to increasing electricty volumes resulting from favorable weather.
Gas Supply Expenses	127	93	(34)	Due to increasing gas volumes resulting from colder than normal weather.	195	162	(33)	Due to increasing gas volumes resulting from colder than normal weather.
Purchased Power	24	30	5		67	72	5	
Other Electric Cost	40	45	5		121	127	6	
Total Cost of Sales	620	543	(77)		1,389	1,313	(76)	
Gross Margin:								
Electric Margin	701	659	42	Higher margins driven by favorable weather and system availability.	1,689	1,664	25	Higher margins driven by favorable weather and system availability.
Gas Margin	79	78	1		157	157	(0)	
Total Gross Margin	780	737	43		1,846	1,820	25	
Operating Expenses:								
O&M	308	306	(2)		742	735	(7)	Due primarily to weather related expenses, partially offset by lower labor related costs.
Depreciation & Amortization	141	142	2		342	344	1	
Taxes, Other than Income	21	21	0		51	51	0	
Total Operating Expenses	470	470	(0)		1,135	1,130	(6)	
Other income	(4)	(4)	0		(7)	(7)	(0)	
EBIT	305	263	42		704	684	20	
Interest Expense	70	72	2		171	172	2	
Income from Ongoing Operations before income taxes	236	191	45		533	511	22	
Income Tax Expense	89	72	(17)	Higher pre-tax income.	200	192	(7)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**$ 147**	**$ 120**	**$ 28**		**$ 333**	**$ 319**	**13**	
Non Operating Income	0	-	0		-	-	-	
Discontinued Operations	(0)	0	(0)		-	0	(0)	
Net Income (loss)	$ 147	$ 120	$ 28		$ 333	$ 320	$ 13	
KY Regulated Financing Costs	(13)	(13)	(0)		(31)	(31)	0	
KY Regulated Net Income	$ 134	$ 107	$ 28		$ 302	$ 288	$ 13	
Earnings Per Share	$ 0.20	$ 0.16	$ 0.04		$ 0.45	$ 0.43	$ 0.02	

Note: Schedules may not sum due to rounding.

Electric Gross Margin   May 2014

($ Millions)

	MTD						YTD					
	Actual	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**	**Actual**	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**
Base Electric Margin:						● **$ 4**						● **$ 26**
Energy Volumes (a)	2,618,020	2,578,293	39,726	$ -	$ 3		13,947,472	13,301,853	645,618	$ -	$ 23	
Energy Prices (a)					(0)						(4)	
Customer Charges (Avg. Customers)	938,525	946,640	(8,115)		(0)		939,691	945,482	(5,792)		-	
Demand Charges (b)	41	39			2		192	185			7	
ECR:						◆ **$ (0)**						◆ **$ (1)**
Average Rate Base	$ 1,342	$ 1,307	$ 35	10.37%	$ 0.3		$ 1,226	$ 1,209	$ 17	10.39%	$ 0.6	
Cost of Capital	10.21%	10.37%	-0.16%	$ 1,342	$ (0.2)		10.21%	10.39%	-0.18%	$ 1,226	(0.8)	
Jurisdictional Factor	87.32%	87.27%	0.04%	$ 1,342	$ -		86.15%	86.98%	-0.83%	$ 1,226	(0.4)	
Other					$ (0.2)						(0.3)	
DSM:						◆ **$ (0)**						◆ **$ (3)**
Program Expense (Revenue Net of Expense)	$ -	$ -			$ -		$ (0.2)	$ 0.2			$ (0.4)	
Lost Sales	1.7	1.9			$ (0.2)		7.1	9.3			(2.2)	
Incentive	0.1	0.1			$ -		0.4	0.3			0.1	
Balancing Adjustment	-	-			$ -		(0.3)	-			(0.3)	
Net Fuel Recovery	$ 0.5	$ (0.3)				● **$ 1**	$ (3)	$ (2)				◆ **$ (1)**
Purchase Power Demand	(2.3)	(2.6)				● **$ 0**	(10.7)	(12.8)				● **$ 2**
Transmission	1.0	1.0				● **$ -**	4.9	4.0				● **$ 1**
Other	(1.3)	(3.0)				● **$ 2**	(6.1)	(15.1)				● **$ 9**
Retail Margin Variance						● **$ 7**						● **$ 33**
Off-System Margin Variance						● **$ 0**						● **$ 9**
Electric Margin Variance						● **$ 7**						● **$ 42**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			**Budget**			**Variance**		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 37	747,842	$ 49.31	$ 33	673,629	$ 49.28	● $4	● $4	● $0
Commercial	19	633,884	30.32	20	642,411	31.14	◆ ($1)	◆ ($0)	◆ ($1)
Industrial	8	857,712	8.93	8	876,885	8.86	◆ ($0)	◆ ($0)	● $0
Municipals	1	146,496	7.17	1	150,737	5.56	● $0	● $0	● $0
Other	5	232,085	22.62	5	234,632	22.96	◆ ($0)	◆ ($0)	◆ ($0)
Native Load Total	**$ 70**	**2,618,020**	**$ 26.76**	**$ 67**	**2,578,293**	**$ 26.06**	● **$3**	● **$3**	◆ **($0)**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			**Budget**			**Variance**		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 231	4,763,272	$ 48.54	$ 215	4,424,065	$ 48.70	● $16	● $17	◆ ($1)
Commercial	100	3,193,680	31.28	100	3,069,012	32.41	● $0	● $4	◆ ($4)
Industrial	36	4,045,985	8.95	35	3,931,432	8.94	● $1	● $1	● $0
Municipals	5	787,114	5.86	4	784,396	5.56	● $0	● $0	● $0
Other	28	1,157,420	23.72	26	1,092,949	23.72	● $2	● $2	● $0
Native Load Total	**$ 399**	**13,947,472**	**$ 28.63**	**$ 380**	**13,301,853**	**$ 28.59**	● **$19**	● **$23**	◆ **($4)**

(b) Demand Analysis (net of base ECR revenue):

	MTD			YTD		
$mil	**Act**	**Bud**	**Variance**	**Act**	**Bud**	**Variance**
Commercial	14	13	1	65	59	6
Industrial	17	17	0	79	80	(1)
Municipals	4	4	(0)	21	21	0
Other	6	6	1	27	26	2
Native Load Total	**41**	**39**	**2**	**192**	**185**	**7**

Gas Gross Margin May 2014

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	$ 5	$ 5		● $ -	$ 25	$ 25		● $ 0
Gas Supply Costs								
Gas Supply Costs	(7)	(6)	$ (1)		(126)	(93)	$ (33)	
GSC Revenue	6	6	0		124	93	32	
Net Gas Supply Costs				◆ $ (0)				◆ $ (1)
Retail Gas (a)	3	3		◆ $ (0)	57	49		● $ 8
Wholesale Gas (a)	-	-		● $ -	-	-		● $ -
DSM	0	0		● $ -	0	0		● $ -
GLT	1	1		● $ 0	3	3		◆ $ (0)
WNA	-	-		● $ -	(6)	-		◆ $ (6)
Other Margin	0	0		● $ -	1	1		● $ 0
Gas Margin Variance				◆ $ (0)				● $ 1

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 2	610,128	$ 2.64	$ 2	607,297	$ 2.64	● $0	● $ -	● $ -
Commercial	1	276,030	1.86	1	364,309	2.08	◆ ($0)	◆ $ (0)	◆ $ (0)
Industrial	0	83,656	1.53	0	63,660	1.77	● $0	● $ -	● $ -
Public Authority	-	25,392	1.86	0	57,198	1.97	◆ ($0)	◆ $ (0)	● $ -
Transportation	1	901,161	0.93	0.80	984,440	0.78	● $0	◆ $ (0)	● $ 0
Ultimate Consumer	$ 3	1,896,367	$ 1.66	$ 3	2,076,905	$ 1.62	◆ ($0)	◆ $ (0)	● $ 0

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 36	13,639,788	$ 2.64	$ 31	11,791,375	$ 2.64	● $5	● $ 5	● $ -
Commercial	13	6,087,712	2.05	11	5,089,046	2.08	● $2	● $ 2	◆ $ (0)
Industrial	1	611,656	1.91	1	503,224	1.80	● $0	● $ 0	● $ 0
Public Authority	2	952,185	2.01	2	896,034	2.02	● $0	● $ 0	● $ -
Transportation	5	6,696,958	0.77	5	5,955,320	0.77	● $1	● $ 1	● $ -
Ultimate Consumer	$ 57	27,988,299	$ 2.03	$ 49	24,234,998	$ 2.02	● $8	● $ 8	◆ $ (0)

O&M **May 2014**

($ Millions)

	MTD								
	Actual	**Budget**	**Total Variance**	**Labor**	**Outages**	**Outside Services**	**Materials**	**Uncollectible Accounts**	**Other**
Generation	$ 19	$ 19	$ (1)	$ 0	$ (1)	$ (0)	$ 0		$ (0)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	2	2	0	0		0	0		0
Energy Supply and Analysis	1	1	0	(0)		0	0		0
Electric Distribution	7	6	(1)	(0)		(1)	0	(0)	0
Gas Distribution	2	3	0	0		0	(0)	(0)	0
Safety and Security	0	0	(0)	(0)		(0)	0	0	(0)
Customer Services	6	7	0	0		(0)	0	0	0
Chief Operations Officer	**38**	**37**	**(1)**	**0**	**(1)**	**(1)**	**0**	**0**	**0**
Information Technology	4	5	0	0		0	0		(0)
General Counsel	3	3	(0)	0		(0)	0		0
Human Resources	1	1	0	0		0	0		0
Supply Chain	0	0	0	0		0	(0)		0
Chief Administrative Officer	**8**	**8**	**0**	**0**		**(0)**	**0**		**(0)**
Chief Financial Officer	**2**	**2**	**(0)**	**0**		**(0)**	**0**		**(0)**
Corporate	**8**	**12**	**5**	**4**		**0**	**0**		**(0)**
O&M Total MTD	**$ 56**	**$ 60**	**$ 4**	**$ 5**	**$ (1)**	**$ (0)**	**$ 1**	**$ 0**	**$ (1)**

	YTD								
	Actual	**Budget**	**Total Variance**	**Labor**	**Outages**	**Outside Services**	**Materials**	**Uncollectible Accounts**	**Other**
Generation	$ 105	$ 105	$ (1)	$ 2	$ 2	$ (3)	$ (1)		$ (1)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	11	12	0	(0)		0	0		(0)
Energy Supply and Analysis	4	4	0	0		0	0		0
Electric Distribution	36	30	(6)	(1)		(5)	(0)	(0)	(0)
Gas Distribution	13	13	(0)	(0)		0	(0)	(0)	(0)
Safety and Security	1	0	(1)	(1)		(0)	0	0	(0)
Customer Services	34	31	(3)	0		(1)	0	(2)	(0)
Chief Operations Officer	**205**	**195**	**(10)**	**1**	**2**	**(8)**	**(1)**	**(2)**	**(2)**
Information Technology	22	23	1	1		0	(0)		(0)
General Counsel	12	13	0	0		(0)	0		(0)
Human Resources	3	3	0	0		0	0		0
Supply Chain	1	2	0	0		(0)	(0)		0
Chief Administrative Officer	**38**	**40**	**2**	**2**		**0**	**(0)**		**(0)**
Chief Financial Officer	**8**	**8**	**0**	**0**		**(0)**	**0**		**0**
Corporate	**57**	**63**	**5**	**6**		**2**	**1**		**(4)**
O&M Total YTD	**$ 308**	**$ 306**	**$ (2)**	**$ 9**	**$ 2**	**$ (6)**	**$ 0**	**$ (2)**	**$ (6)**

	Full Year								
	Forecast	**Budget**	**Total Variance**	**Labor**	**Outages**	**Outside Services**	**Materials**	**Uncollectible Accounts**	**Other**
Generation	$ 246	$ 245	$ (0)	$ 3	$ (0)	$ (3)	$ 1		$ (1)
Project Engineering	1	1	0	(0)		(0)	(0)		0
Transmission	29	29	(1)	(0)		(0)	(0)		(0)
Energy Supply and Analysis	9	9	0	0		0	0		0
Electric Distribution	74	72	(1)	2		(3)	0	0	(0)
Gas Distribution	32	32	(0)	(0)		(0)	0	0	(0)
Safety and Security	3	0	(3)	(3)		(0)	(0)	0	0
Customer Services	87	79	(8)	(0)		(3)	0	(4)	(0)
Chief Operations Officer	**481**	**468**	**(13)**	**2**	**(0)**	**(10)**	**1**	**(4)**	**(2)**
Information Technology	55	55	0	1		(0)	(0)		(0)
General Counsel	32	32	0	0		0	0		0
Human Resources	8	8	0	0		0	0		0
Supply Chain	4	4	0	0		0	0		0
Chief Administrative Officer	**98**	**98**	**0**	**1**		**0**	**(0)**		**(0)**
Chief Financial Officer	**19**	**19**	**0**	**0**		**0**	**0**		**(0)**
Corporate	**144**	**150**	**6**	**7**		**(0)**	**(0)**	0	**(1)**
O&M Total Full Year	**$ 742**	**$ 735**	**$ (7)**	**$ 9**	**$ (0)**	**$ (10)**	**$ 1**	**$ (4)**	**$ (3)**

Attachment to Filing Requirement
807 KAR 5:001 Section 16(7)(o)
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Witness: K Blake

Note: Schedules may not sum due to rounding.

Financing Activities May 2014

($ Millions)

	MTD			YTD			Full Year		
Balance Sheet	**Actual**	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**	**Forecast**	**Budget**	**Variance**
PCB									
Beg Bal	$ 924.0	$ 924.4	$ 0.4	$ 924.0	$ 924.0	$ 0.0	$ 924.0	$ 924.0	$ -
End Bal	924.0	924.5	0.5	924.0	924.5	0.5	926.0	924.9	(1.1)
Ave Bal	**$ 924.0**	**$ 924.4**	**$ 0.5**	**$ 924.0**	**$ 924.3**	**$ 0.3**	**$ 924.7**	**$ 924.6**	**$ (0.2)**
Interest Exp	**$ 0.8**	**$ 0.9**	**$ 0.2**	**$ 3.8**	**$ 4.7**	**$ 0.9**	**$ 10.8**	**$ 11.3**	**$ 0.6**
Rate	**0.98%**	**1.19%**	**0.21%**	**0.99%**	**1.22%**	**0.23%**	**1.17%**	**1.23%**	**0.06%**
FMB/Sr Nts									
Beg Bal	$ 3,641.5	$ 3,641.4	$ (0.0)	$ 3,640.9	$ 3,640.9	$ -	$ 3,640.9	$ 3,640.9	$ -
End Bal	3,641.6	3,641.6	(0.1)	3,641.6	3,641.6	(0.1)	3,642.6	3,642.5	(0.0)
Ave Bal	**$ 3,641.5**	**$ 3,641.5**	**$ (0.0)**	**$ 3,641.2**	**$ 3,641.3**	**$ 0.0**	**$ 3,641.8**	**$ 3,641.8**	**$ (0.0)**
Interest Exp	**$ 11.5**	**$ 11.6**	**$ 0.1**	**$ 57.5**	**$ 58.2**	**$ 0.7**	**$ 140.9**	**$ 141.4**	**$ 0.4**
Rate	**3.67%**	**3.71%**	**0.05%**	**3.76%**	**3.81%**	**0.05%**	**3.87%**	**3.88%**	**0.01%**
Short-term Debt									
Beg Bal	$ 177.0	$ 247.9	$ 70.9	$ 245.0	$ 245.0	$ -	$ 245.0	$ 245.0	$ -
End Bal	250.0	351.4	101.4	250.0	351.4	101.4	543.4	527.8	(15.6)
Ave Bal	**$ 213.5**	**$ 299.6**	**$ 86.1**	**$ 247.5**	**$ 258.9**	**$ 11.4**	**$ 368.1**	**$ 356.8**	**$ (11.3)**
Interest Exp	**$ 0.1**	**$ 0.4**	**$ 0.3**	**$ 0.8**	**$ 1.8**	**$ 1.0**	**$ 3.4**	**$ 3.6**	**$ 0.2**
Rate	**0.35%**	**1.49%**	**1.14%**	**0.80%**	**1.68%**	**0.88%**	**0.91%**	**1.00%**	**0.09%**
Total End Bal	**$ 4,815.6**	**$ 4,917.5**	**$ 101.9**	**$ 4,815.6**	**$ 4,917.5**	**$ 101.9**	**$ 5,112.0**	**$ 5,095.3**	**$ (16.7)**
Total Average Bal	**$ 4,779.0**	**$ 4,865.6**	**$ 86.6**	**$ 4,812.7**	**$ 4,824.5**	**$ 11.8**	**$ 4,934.7**	**$ 4,923.2**	**$ (11.5)**
Total Expense Excl I/C	**$ 13.9**	**$ 14.3**	**$ 0.4**	**$ 69.5**	**$ 71.6**	**$ 2.1**	**$ 171.2**	**$ 172.4**	**$ 1.2**
Rate	**3.39%**	**3.42%**	**0.04%**	**3.44%**	**3.54%**	**0.09%**	**3.47%**	**3.50%**	**0.03%**

Credit Facilities ($ Millions)	**Committed Capacity**	**Borrowed**	**Letters of Credit Issued**	**Unused Capacity**
LKE	$ 300	$ 75		$ 225
LG&E	500	50		450
KU	598	125	$ 198	275
TOTAL	$ 1,398	$ 250	$ 198	$ 950

Credit Metrics	**YTD**		**Full Year**	
($ Millions)	**Actual**	**+/- Bud**	**Forecast**	**+/- Bud**
FFO to Debt - LG&E	29.6%	+0.02	21.6%	-0.01
FFO to Debt - KU	27.5%	+0.03	22.7%	-0.01
Debt to EBITDA - LG&E (1)	3.04	-0.63	3.59	-0.07
Debt to EBITDA - KU (1)	3.50	-0.22	3.67	-0.05
Debt to Capitalization - LG&E (2)	47.1%	+0.01	47.0%	-0.00
Debt to Capitalization - KU (2)	47.1%	-0.01	47.0%	-0.00

(1) Actuals represent a trailing 12 months

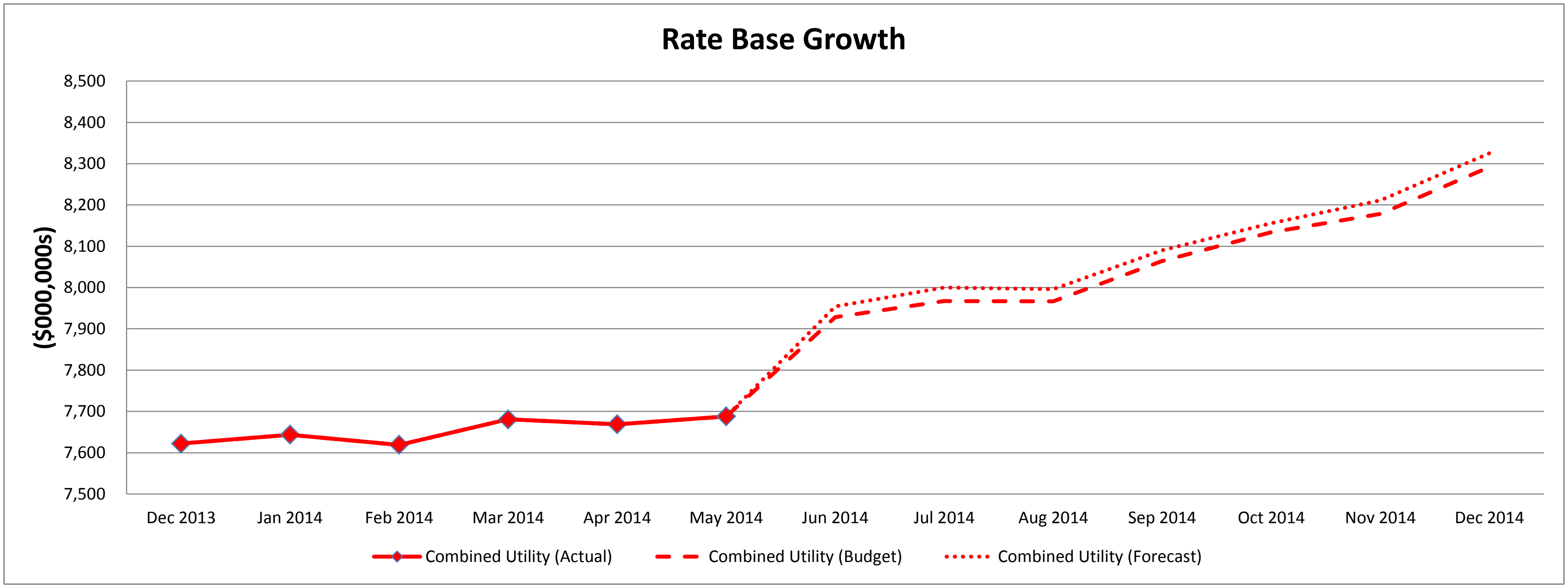
(2) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet May 2014

($ Millions)

	5/31/2014	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 9	$ 9	$ (0)	
Accounts Receivable (Trade)	369	396	(27)	Lower unbilled utility revenue ($34m) off set by higher customer accounts receivable ($10m).
Inventory	239	235	5	
Deferred Income Taxes	139	159	(20)	Deferred Income Taxes reclassified from asset to liability Deferred Tax Liabilities.
Prepayments and other current assets	47	114	(66)	Lower notes receivable from affiliate ($67m).
Total Current Assets	803	912	(109)	
Property, Plant, and Equipment	9,868	9,904	(36)	Lower Electric Plant In Service ($90m) and CWIP ($19m) partially offet by higher completed construction electric ($62m).
Intangible Assets	201	201	(0)	
Other Property and Investments	1	1	(0)	
Regulatory Assets	508	490	18	Higher GSC revenue ($14m).
Goodwill	997	997	0	
Other Long-term Assets	95	94	1	
Total Assets	**$ 12,473**	**$ 12,599**	**$ (126)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 350	$ 332	$ 18	Primarily due to higher fuel volumes.
Accounts Payable - Affiliated Company	117	0	117	Dividend payable ($117m) issued to PPL based on Q1 2014 net income.
Customer Deposits	50	50	0	
Derivative Liability	4	4	1	
Accrued Taxes	64	71	(7)	
Other Current Liabilities	130	109	21	Mostly due to $31m in payments on the last business day of the month out the A/P account which didn't have time to be funded from the Funding Account, creating negative cash in the A/P account and a liability in the credit cash adjustment account.
Total Current Liabilities	716	566	150	
Debt - Affiliated Company	-	20	(20)	Budget had a short term debt issuance at LKE Other. An inter company receivable should have been used instead of issuing debt.
Debt [(1)]	4,816	4,897	(82)	Lower issuance of Commercial Paper ($82m) due to lower pension and capex payments.
Total Debt	4,816	4,917	(102)	
Deferred Tax Liabilities	1,019	1,041	(21)	Deferred Tax Liabilities reclassified from liability to asset as Deferred Income Taxes.
Investment Tax Credit	133	133	(0)	
Accum Provision for Pension & Related Benefits	118	120	(2)	
Asset Retirement Obligation	253	247	5	
Regulatory Liabilities	1,025	1,030	(5)	
Derivative Liability	39	32	7	
Other Liabilities	239	237	2	
Total Deferred Credits and Other Liabilities	2,826	2,841	(14)	
Equity	4,115	4,275	(160)	
Total Liabilities and Equity	**$ 12,473**	**$ 12,599**	**$ (126)**	

(1) Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.


Rate Base Growth
($000,000s)
8,500
8,400
8,300
8,200
8,100
8,000
7,900
7,800
7,700
7,600
7,500
Dec 2013
Jan 2014
Feb 2014
Mar 2014
Apr 2014
May 2014
Jun 2014
Jul 2014
Aug 2014
Sep 2014
Oct 2014
Nov 2014
Dec 2014
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Forecast)

Performance Report

June 2014

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Kentucky Regulated Dashboard

June 2014

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.00	3.28	0.94	1.38	0.94	1.29
Employee lost-time incidents	0	1	4	1	4	3
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,055	3,083	17,570	16,850	35,530	34,780
Utility EFOR	5.8%	5.9%	4.2%	5.9%	N/A	5.9%
Utility EAF	90.7%	92.3%	79.5%	79.6%	N/A	82.5%
Steam Fleet Commercial Availability	93.0%	91.5%	94.5%	91.5%	N/A	91.5%
Combined SAIFI	0.10	0.17	0.51	0.60	N/A	1.20
Combined SAIDI (minutes)	9.86	14.76	47.34	54.87	N/A	107.60
GwH Sales						
Residential	939	935	5,702	5,359	11,329	10,962
Commercial	693	729	3,887	3,798	8,000	7,952
Industrial	867	897	4,913	4,829	9,946	10,011
Municipals	166	172	953	957	1,915	1,969
Other	254	250	1,411	1,343	2,832	2,788
Off-System Sales	46	22	309	195	386	273
Total	2,965	3,006	17,176	16,481	34,408	33,954
Weather-Normalized Sales Growth			**TTM**			
Residential			-0.63%			
Commercial			0.33%			
Industrial			1.26%			
Municipal			-0.81%			
Other			0.44%			
Total			0.23%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[1]	10.8%	9.9%	10.0%	8.4%	9.1%	8.7%
Electric Margins	$147	$146	$848	$805	$1,680	$1,664
Gas Margins	8	8	88	87	158	157
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	($0)	$9	$59	$81	$118	$126
ECR	$54	$55	$309	$302	$703	$603
Generation	$4	$6	$32	$41	$116	$121
Transmission	$5	$4	$41	$38	$85	$77
Electric Distribution	$12	$13	$59	$68	$147	$143
Gas Distribution	$7	$8	$32	$38	$79	$80
Customer Services	$3	$2	$8	$10	$18	$20
IT and Other	$2	$4	$14	$25	$40	$50
Total	$86	$100	$553	$603	$1,306	$1,221
O&M ($ millions)[2]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$35	$37	$241	$232	$483	$468
Administrative	9	8	$47	49	98	98
Finance	2	2	$9	10	19	19
Burdens & Other Charges	9	13	$66	75	133	150
Total	$55	$59	$364	$366	$733	$735
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,459	3,559	3,459	3,559	3,502	3,549
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	2	0	8	3	N/A	14
NERC Possible Violations	2	4	3	7	N/A	11

Variance Explanations

- YTD generation volumes and GWh sales were impacted by favorable weather. Generation volumes were also impacted by favorable plant availability.

- MTD and YTD capital spend lower due primarily to timing of spending on Cane Run Unit 7 and other projects.

- Full year higher capital due primarily to increased costs related to Ghent environmental air projects (Units 3 and 4 economizer work) and Mill Creek environmental air projects (Units 1, 2 and 4 fabric filters and wet flue gas desulfurization units) with some non-environmental spend offsets due to cost reductions.

- YTD higher margins driven principally by retail electric energy and demand revenues supported by favorable weather as well as $8 million from excess generation driven by favorable plant availability and higher market prices and $6 million from lower margin expenses driven by lower ammonia and limestone costs.

- MTD lower O&M primarily due to $3 million of labor and benefit savings and $1 million due to timing of maintenance.

Major Developments

- LKE reached an extraordinary safety accomplishment on June 30, as it completed 30 straight days with zero injuries. The feat demonstrates LKE's commitment to excellent safety performance during the current execution of the largest construction program in our history.

- LKE continues to gain industry recognition as it was recently honored for new customer service and communication initiatives. IVR Doctors and Market Strategies International acknowledged LKE's interactive voice response (IVR) system as the best among combined utilities with the "Gold Stethoscope" award. LKE has added new options to the IVR, allowing customers to automatically enroll in energy efficiency programs and apply for rebates. LKE also earned 14 awards in various categories in the 2014 Better Communications Competition held during the Utility Communicators International conference. LKE surpassed its own record and all other utilities for the most awards and received the prestigious "Communicator of the Year" Award. LKE highlighted its Energy Education initiative which assists the public in better understanding its actions concerning various industry topics.

- The nine terminating municipal customers rejected KU's last settlement position and stated that they would not be rescinding their termination notice. KU is continuing its evaluation of the decision on its future resource plans, including the Green River 5 CPCN.

Significant Future Events

- An informal conference related to the Green River 5 CPCN is scheduled for August 12.

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(1) Excludes goodwill and other purchase accounting adjustments.

(2) Net of cost recovery mechanisms.

Income Statement: Actual vs. Budget and Forecast (Month) June 2014

($ Millions)

	MTD				MTD			
	Actual	**Budget**	**Variance**	**Comments**	**Actual**	**Q1 Forecast**	**Variance**	**Comments**
Revenues:								
Electric Revenues	$ 246	$ 250	$ (4)		$ 246	$ 250	$ (4)	
Gas Revenues	14	12	1		14	12	1	
Total Revenues	259	262	(3)		259	262	(3)	
Cost of Sales:								
Fuel Electric Costs	83	84	1		83	84	1	
Gas Supply Expenses	5	4	(1)		5	4	(1)	
Purchased Power	4	5	1		4	5	1	
Other Electric Cost	11	14	3		11	14	3	
Total Cost of Sales	103	107	4		103	107	4	
Gross Margin:								
Electric Margin	147	146	1		147	146	1	
Gas Margin	8	8	0		8	8	0	
Total Gross Margin	155	154	1		155	155	1	
Operating Expenses:								
O&M	55	59	4	Due to labor and benefit savings ($3m) and timing of maintenance ($1m).	55	60	5	Due to labor and benefit savings ($3m) and timing of maintenance ($1m).
Depreciation & Amortization	28	29	0		28	29	0	
Taxes, Other than Income	4	4	0		4	4	0	
Total Operating Expenses	88	92	4		88	93	5	
Other income	(0)	(0)	(0)		(0)	(0)	(0)	
EBIT	67	62	5		67	61	6	
Interest Expense	14	14	1		14	14	0	
Income from Ongoing Operations before income taxes	54	48	6		54	47	7	
Income Tax Expense	21	18	(3)		21	17	(4)	
Net Income (loss) from ongoing operations	**$ 33**	**$ 30**	**$ 3**		**$ 33**	**29**	**$ 4**	
Non Operating Income	0	0	0		0	0	0	
Discontinued Operations	(0)	0	(0)		(0)	0	(0)	
Net Income (loss)	$ 33	$ 30	$ 3		$ 33	$ 29	$ 4	
KY Regulated Financing Costs	(3)	(3)	(0)		(3)	(3)	(0)	
KY Regulated Net Income	$ 30	$ 27	$ 3		$ 30	$ 27	$ 4	
Earnings Per Share	$ 0.05	$ 0.04	$ 0.01		$ 0.05	$ 0.04	$ 0.01	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) June 2014

($ Millions)

	YTD			
	Actual	**Budget**	**Variance**	**Comments**
Revenues:				
Electric Revenues	$ 1,439	$ 1,358	$ 81	Due to higher electricity volumes resulting from favorable weather.
Gas Revenues	220	184	36	Due to higher gas volumes resulting from colder than normal weather.
Total Revenues	1,659	1,542	117	
Cost of Sales:				
Fuel Electric Costs	512	459	(53)	Due to higher electricity volumes resulting from favorable weather.
Gas Supply Expenses	132	97	(35)	Due to higher gas volumes resulting from colder than normal weather.
Purchased Power	29	35	6	Due to lower purchases than planned.
Other Electric Cost	51	59	8	Due primarily to lower plant system consumables costs.
Total Cost of Sales	724	650	(73)	
Gross Margin:				
Electric Margin	848	805	43	Higher margins driven by favorable weather and system availability.
Gas Margin	88	87	1	
Total Gross Margin	936	892	44	
Operating Expenses:				
O&M	364	366	2	
Depreciation & Amortization	169	171	2	
Taxes, Other than Income	25	25	0	
Total Operating Expenses	558	562	4	
Other income	(5)	(5)	0	
EBIT	373	325	48	
Interest Expense	83	86	3	
Income from Ongoing Operations before income taxes	289	239	50	
Income Tax Expense	110	90	(20)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**$ 180**	**$ 149**	**$ 30**	
Non Operating Income	0	-	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 180	$ 150	$ 30	
KY Regulated Financing Costs	(16)	(16)	(0)	
KY Regulated Net Income	$ 164	$ 134	$ 30	
Earnings Per Share	$ 0.25	$ 0.20	$ 0.05	

Note: Schedules may not sum due to rounding.

Income Statement: Forecast vs. Prior Forecast & Budget June 2014

($ Millions)

	Full Year				Full Year			
	Q2 Forecast	Q1 Forecast	Variance	Comments	Q2 Forecast	Budget	Variance	Comments
Revenues:								
Electric Revenues	$ 2,873	$ 2,877	$ (4)		$ 2,873	$ 2,815	$ 58	Due to higher electricity volumes resulting from favorable weather.
Gas Revenues	355	351	4		355	318	36	Due to higher gas volumes resulting from colder than normal weather.
Total Revenues	3,228	3,227	0		3,228	3,134	94	
Cost of Sales:								
Fuel Electric Costs	1,011	996	(15)	Due to higher electricity volumes resulting from favorable weather.	1,011	953	(58)	Due to higher electricity volumes resulting from favorable weather.
Gas Supply Expenses	197	193	(4)	Due to higher electricity volumes resulting from favorable weather.	197	162	(36)	Due to higher gas volumes resulting from colder than normal weather.
Purchased Power	66	69	3		66	72	6	Due to lower purchases than planned.
Other Electric Cost	117	124	7	Due primarily to lower plant system consumables costs.	117	127	10	Due primarily to lower plant system consumables costs.
Total Cost of Sales	1,390	1,381	(9)		1,390	1,313	(77)	
Gross Margin:								
Electric Margin	1,680	1,689	(9)	Due to higher cost of sales (see above).	1,680	1,664	16	Due to higher revenues offset by higher cost of sales (see above).
Gas Margin	158	158	0		158	157	1	
Total Gross Margin	1,837	1,846	(9)		1,837	1,820	17	
Operating Expenses:								
O&M	733	742	9	Due primarily to lower pension and medical related expenses.	733	735	2	
Depreciation & Amortization	342	343	1		342	344	2	
Taxes, Other than Income	51	51	(0)		51	51	(0)	
Total Operating Expenses	1,126	1,135	9		1,126	1,130	3	
Other income	(7)	(6)	(0)		(7)	(7)	0	
EBIT	704	705	(0)		704	684	20	
Interest Expense	170	171	1		170	172	3	
Income from Ongoing Operations before income taxes	534	533	1		534	511	23	
Income Tax Expense	202	200	(2)	Higher pre-tax income.	202	192	(9)	
Net Income (loss) from ongoing operations	**$ 333**	**$ 333**	**$ (1)**		**$ 333**	**$ 319**	**$ 13**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	0	0	(0)		0	0	(0)	
Net Income (loss)	$ 333	$ 334	$ (1)		$ 333	$ 320	$ 14	
KY Regulated Financing Costs	(31)	(31)	0		(31)	(31)	0	
KY Regulated Net Income	$ 302	$ 302	$ (0)		$ 302	$ 288	$ 14	
Earnings Per Share	$ 0.45	$ 0.45	$ 0.00		$ 0.45	$ 0.43	$ 0.02	

Note: Schedules may not sum due to rounding.

Electric Gross Margin June 2014

($ Millions)

	MTD						YTD					
	Actual	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**	**Actual**	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**
Base Electric Margin:						◆ **$ (4)**						● **$ 22**
Energy Volumes (a)	2,918,792	2,983,975	(65,183)	$ -	$ (1)		16,866,264	16,285,829	580,435	$ -	$ 22	
Energy Prices (a)					(2)						(6)	
Customer Charges (Avg. Customers)	938,154	946,652	(8,498)		(0)		939,435	945,677	(6,243)		(0)	
Demand Charges (b)	43	43			0		235	228			7	
ECR:						● **$ 0**						◆ **$ (1)**
Average Rate Base	$ 1,401	$ 1,318	$ 83	10.37%	$ 0.6		$ 1,255	$ 1,227	$ 28	10.38%	$ 1.2	
Cost of Capital	10.11%	10.37%	-0.26%	$ 1,401	$ (0.3)		10.19%	10.38%	-0.19%	$ 1,255	(1.0)	
Jurisdictional Factor	90.26%	89.83%	0.43%	$ 1,401	$ 0.1		86.91%	87.49%	-0.58%	$ 1,255	(0.4)	
Other					$ (0.1)						(0.4)	
DSM:						● **$ 1**						◆ **$ (2)**
Program Expense (Revenue Net of Expense)	$ -	$ -			$ -		$ (0.2)	$ 0.2			$ (0.4)	
Lost Sales	3.1	1.9			$ 1.2		10.2	11.2			(1.0)	
Incentive	0.2	0.2			$ -		0.6	0.6			-	
Balancing Adjustment	-	-			$ -		(0.3)	-			(0.3)	
Net Fuel Recovery	$ (0.7)	$ (0.3)				◆ **$ (0)**	$ (4)	$ (2)				◆ **$ (1)**
Purchase Power Demand	(2.0)	(2.5)				● **$ 1**	(12.6)	(15.3)				● **$ 3**
Transmission	1.0	1.2				◆ **$ (0)**	5.9	5.2				● **$ 1**
Other	(1.5)	(3.8)				● **$ 2**	(7.5)	(18.9)				● **$ 11**
Retail Margin Variance						● **$ 0**						● **$ 34**
Off-System Margin Variance						● **$ 0**						● **$ 8**
Electric Margin Variance						● **$ 1**						● **$ 43**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 46	939,055	$ 49.25	$ 46	934,713	$ 49.13	● $0	● $0	● $0
Commercial	21	692,554	30.12	23	729,103	31.88	◆ ($2)	◆ ($1)	◆ ($1)
Industrial	8	867,049	9.03	8	897,469	9.01	◆ ($0)	◆ ($0)	● $0
Municipals	1	166,345	2.87	1	172,227	5.57	◆ ($1)	● $0	◆ ($0)
Other	5	253,790	20.52	6	250,463	23.05	◆ ($1)	● $0	◆ ($1)
Native Load Total	**$ 81**	**2,918,792**	**$ 27.62**	**$ 84**	**2,983,975**	**$ 28.15**	◆ **($3)**	◆ **($1)**	◆ **($2)**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 277	5,702,328	$ 48.65	$ 261	5,358,778	$ 48.77	● $16	● $17	◆ ($1)
Commercial	121	3,886,234	31.08	123	3,798,115	32.31	◆ ($2)	● $3	◆ ($5)
Industrial	44	4,913,034	8.96	43	4,828,901	8.96	● $1	● $1	● $0
Municipals	5	953,459	5.34	5	956,623	5.56	◆ ($0)	● $0	◆ ($0)
Other	33	1,411,209	23.14	32	1,343,412	23.60	● $1	● $2	◆ ($1)
Native Load Total	**$ 480**	**16,866,264**	**$ 28.46**	**$ 464**	**16,285,829**	**$ 28.51**	● **$16**	● **$22**	◆ **($6)**

(b) Demand Analysis (net of base ECR revenue):

	MTD			YTD		
$mil	Act	Bud	Variance	Act	Bud	Variance
Commercial	15	14	1	80	73	7
Industrial	17	18	(1)	96	98	(2)
Municipals	5	5	(0)	25	25	0
Other	7	6	0	34	32	2
Native Load Total	**43**	**43**	**0**	**235**	**228**	**7**

Gas Gross Margin June 2014

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		● **$ -**	**$ 30**	**$ 30**		● **$ 0**
Gas Supply Costs								
Gas Supply Costs	(5)	(3)	$ (2)		(131)	(96)	$ (35)	
GSC Revenue	5	3	2		130	96	34	
Net Gas Supply Costs				● **$ 0**				◆ **$ (1)**
Retail Gas (a)	**3**	**3**		● **$ 0**	**59**	**52**		● **$ 8**
Wholesale Gas (a)	**-**	**-**		● **$ -**	**-**	**-**		● **$ -**
DSM	**-**	**0**		◆ **$ (0)**	**0**	**0**		◆ **$ (0)**
GLT	**0**	**1**		◆ **$ (0)**	**3**	**4**		◆ **$ (1)**
WNA	**-**	**-**		● **$ -**	**(6)**	**-**		◆ **$ (6)**
Other Margin	**0**	**0**		● **$ -**	**1**	**1**		● **$ 0**
Gas Margin Variance				◆ **$ (0)**				● **$ 1**

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 1	417,454	$ 2.64	$ 1	418,942	$ 2.64	● $0	● $ -	● $ -
Commercial	1	262,919	1.94	1	249,652	2.08	● $0	● $ -	● $ -
Industrial	0	103,092	1.27	0	48,453	1.66	● $0	● $ 0	● $ -
Public Authority	0	45,222	1.58	0	31,242	1.86	● $0	● $ -	● $ -
Transportation	1	886,006	0.92	0.70	783,625	0.92	● $0	● $ 0	● $ -
Ultimate Consumer	$ 3	1,714,693	$ 1.53	$ 3	1,531,914	$ 1.62	● $0	● $ 0	◆ $ (0)

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 37	14,057,242	$ 2.64	$ 32	12,210,317	$ 2.64	● $5	● $ 5	● $ -
Commercial	13	6,350,631	2.05	11	5,338,698	2.08	● $2	● $ 2	◆ $ (0)
Industrial	1	714,748	1.81	1	551,676	1.78	● $0	● $ 0	● $ -
Public Authority	2	997,407	1.99	2	927,276	2.01	● $0	● $ 0	● $ -
Transportation	6	7,582,964	0.79	5	6,738,945	0.79	● $1	● $ 1	● $ -
Ultimate Consumer	$ 59	29,702,992	$ 2.00	$ 52	25,766,912	$ 2.00	● $8	● $ 8	◆ $ (0)

O&M June 2014

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 17	$ 18	$ 1	$ 0	$ (1)	$ 1	$ 1		$ (0)
Project Engineering	0	0	(0)	(0)		(0)	(0)		0
Transmission	3	3	(0)	(0)		(0)	0		0
Energy Supply and Analysis	1	1	0	(0)		0	0		0
Electric Distribution	6	6	0	(0)		1	0	(0)	(0)
Gas Distribution	2	3	1	0		0	0	(0)	0
Safety and Security	0	0	(0)	(0)		(0)	0	0	(0)
Customer Services	7	6	(0)	(0)		(0)	(0)	0	(0)
Chief Operations Officer	**35**	**37**	**1**	**(1)**	**(1)**	**1**	**2**	**0**	**(0)**
Information Technology	4	5	1	0		0	0		0
General Counsel	4	3	(1)	0		(1)	(0)		(0)
Human Resources	1	1	0	0		0	0		0
Supply Chain	0	0	(0)	(0)		0	0		0
Chief Administrative Officer	**9**	**8**	**(0)**	**0**		**(1)**	**0**		**(0)**
Chief Financial Officer	**2**	**2**	**(0)**	**0**		**0**	**0**		**(0)**
Corporate	**9**	**13**	**4**	**3**		**0**	**0**		**(0)**
O&M Total MTD	**$ 55**	**$ 59**	**$ 4**	**$ 3**	**$ (1)**	**$ 1**	**$ 2**	**$ 0**	**$ (1)**

	YTD								
	Actual	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 122	$ 123	$ 1	$ 3	$ 1	$ (2)	$ 0		$ (1)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	14	14	0	(0)		(0)	1		(0)
Energy Supply and Analysis	4	5	0	0		0	0		0
Electric Distribution	42	37	(6)	(1)		(4)	0	(0)	(0)
Gas Distribution	15	16	0	(0)		1	(0)	(0)	(0)
Safety and Security	2	0	(1)	(1)		(0)	0	0	(0)
Customer Services	41	38	(3)	0		(1)	0	(1)	(0)
Chief Operations Officer	**241**	**232**	**(8)**	**0**	**1**	**(6)**	**1**	**(1)**	**(3)**
Information Technology	26	28	2	2		0	(0)		(0)
General Counsel	16	15	(1)	0		(1)	0		(0)
Human Resources	4	4	0	0		0	0		0
Supply Chain	2	2	0	0		0	(0)		0
Chief Administrative Officer	**47**	**49**	**1**	**2**		**(0)**	**(0)**		**(0)**
Chief Financial Officer	**9**	**10**	**0**	**0**		**0**	**0**		**(0)**
Corporate	**66**	**75**	**9**	**10**		**2**	**1**	**(0)**	**(4)**
O&M Total YTD	**$ 364**	**$ 366**	**$ 2**	**$ 12**	**$ 1**	**$ (5)**	**$ 2**	**$ (2)**	**$ (6)**

	Full Year								
	Forecast	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 244	$ 245	$ 1	$ 3	$ 1	$ (4)	$ 1		$ (1)
Project Engineering	1	1	0	(0)		(0)	(0)		0
Transmission	29	29	(1)	(0)		0	(1)		0
Energy Supply and Analysis	9	9	0	0		0	0		0
Electric Distribution	77	72	(5)	0		(4)	0	0	(1)
Gas Distribution	32	32	(0)	(0)		0	0	0	(0)
Safety and Security	3	0	(3)	(3)		(0)	0	0	(0)
Customer Services	87	79	(8)	(0)		(3)	0	(5)	(1)
Chief Operations Officer	**483**	**468**	**(16)**	**0**	**1**	**(10)**	**1**	**(5)**	**(3)**
Information Technology	55	55	0	1		(0)	(0)		(0)
General Counsel	32	32	0	(0)		0	0		(0)
Human Resources	8	8	0	0		0	0		0
Supply Chain	4	4	(0)	(0)		0	0		0
Chief Administrative Officer	**98**	**98**	**1**	**1**		**(0)**	**(0)**		**(0)**
Chief Financial Officer	**19**	**19**	**0**	**0**		**0**	**0**		**(0)**
Corporate	**133**	**150**	**17**	**19**		**1**	**(0)**	**(0)**	**(3)**
O&M Total Full Year	**$ 733**	**$ 735**	**$ 2**	**$ 20**	**$ 1**	**$ (9)**	**$ 1**	**$ (5)**	**$ (5)**

Note: Schedules may not sum due to rounding.

Financing Activities June 2014

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB									
Beg Bal	$ 924.0	$ 924.5	$ 0.5	$ 924.0	$ 924.0	$ 0.0	$ 924.0	$ 924.0	$ -
End Bal	924.0	924.5	0.5	924.0	924.5	0.5	925.8	924.9	(0.8)
Ave Bal	**$ 924.0**	**$ 924.5**	**$ 0.5**	**$ 924.0**	**$ 924.3**	**$ 0.4**	**$ 924.5**	**$ 924.6**	**$ 0.1**
Interest Exp	**$ 0.8**	**$ 0.9**	**$ 0.2**	**$ 4.6**	**$ 5.7**	**$ 1.1**	**$ 10.3**	**$ 11.3**	**$ 1.1**
Rate	**1.01%**	**1.23%**	**0.21%**	**0.99%**	**1.22%**	**0.23%**	**1.11%**	**1.23%**	**0.12%**
FMB/Sr Nts									
Beg Bal	$ 3,641.6	$ 3,641.6	$ (0.1)	$ 3,640.9	$ 3,640.9	$ -	$ 3,640.9	$ 3,640.9	$ -
End Bal	3,641.8	3,641.7	(0.1)	3,641.8	3,641.7	(0.1)	3,642.6	3,642.5	(0.1)
Ave Bal	**$ 3,641.7**	**$ 3,641.6**	**$ (0.1)**	**$ 3,641.3**	**$ 3,641.4**	**$ 0.0**	**$ 3,641.8**	**$ 3,641.8**	**$ (0.0)**
Interest Exp	**$ 11.9**	**$ 11.6**	**$ (0.3)**	**$ 69.4**	**$ 69.8**	**$ 0.4**	**$ 140.5**	**$ 141.4**	**$ 0.8**
Rate	**3.93%**	**3.84%**	**-0.09%**	**3.79%**	**3.81%**	**0.02%**	**3.86%**	**3.88%**	**0.02%**
Short-term Debt									
Beg Bal	$ 250.0	$ 351.4	$ 101.4	$ 245.0	$ 245.0	$ -	$ 245.0	$ 245.0	$ -
End Bal	320.0	371.7	51.7	320.0	371.7	51.7	570.9	527.8	(43.1)
Ave Bal	**$ 285.0**	**$ 361.5**	**$ 76.6**	**$ 282.5**	**$ 277.7**	**$ (4.8)**	**$ 357.6**	**$ 356.8**	**$ (0.8)**
Interest Exp	**$ 0.2**	**$ 0.3**	**$ 0.1**	**$ 1.0**	**$ 1.6**	**$ 0.6**	**$ 3.1**	**$ 3.6**	**$ 0.5**
Rate	**0.76%**	**1.01%**	**0.24%**	**0.71%**	**1.14%**	**0.43%**	**0.87%**	**1.00%**	**0.14%**
Total End Bal	**$ 4,885.7**	**$ 4,937.8**	**$ 52.1**	**$ 4,885.7**	**$ 4,937.8**	**$ 52.1**	**$ 5,139.3**	**$ 5,095.3**	**$ (44.0)**
Total Average Bal	**$ 4,850.6**	**$ 4,927.6**	**$ 77.0**	**$ 4,847.8**	**$ 4,843.3**	**$ (4.4)**	**$ 4,923.9**	**$ 4,923.2**	**$ (0.7)**
Total Expense Excl I/C (1)	**$ 13.9**	**$ 14.4**	**$ 0.5**	**$ 83.4**	**$ 86.0**	**$ 2.6**	**$ 169.7**	**$ 172.4**	**$ 2.7**
Rate	**3.43%**	**3.50%**	**0.07%**	**3.42%**	**3.53%**	**0.11%**	**3.45%**	**3.50%**	**0.05%**

(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	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 75		$ 225
LG&E	500	70		430
KU	598	175	$ 198	225
TOTAL	$ 1,398	$ 320	$ 198	$ 880

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud	Full Year Forecast	Full Year +/- Bud
FFO to Debt - LG&E	28.6%	+0.02	21.6%	-0.01
FFO to Debt - KU	24.8%	+0.01	22.7%	-0.01
Debt to EBITDA - LG&E (1)	3.04	-0.62	3.59	-0.07
Debt to EBITDA - KU (1)	3.57	-0.16	3.67	-0.05
Debt to Capitalization - LG&E (2)	46.3%	+0.00	47.0%	-0.00
Debt to Capitalization - KU (2)	47.2%	-0.01	47.0%	-0.00

(1) Actuals represent a trailing 12 months

(2) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet June 2014

($ Millions)

	6/30/2014	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 23	$ 9	$ 14	Excess daily operational funds.
Accounts Receivable (Trade)	397	418	(21)	Lower unbilled utility revenue ($26m) offset by higher customer accounts receivable ($6m).
Inventory	235	238	(3)	
Deferred Income Taxes	108	159	(51)	Deferred Income Taxes reclassified from asset to liability Deferred Tax Liabilities.
Prepayments and other current assets	63	112	(49)	Lower notes receivable from affiliate ($54m).
Total Current Assets	826	936	(111)	
Property, Plant, and Equipment	9,926	9,974	(48)	Lower Electric Plant In Service ($329m) and CWIP ($42m) partially offset by higher completed construction electric ($308m).
Intangible Assets	197	197	(0)	
Other Property and Investments	1	1	(0)	
Regulatory Assets	498	487	12	Higher GSC revenue ($15m).
Goodwill	997	997	0	
Other Long-term Assets	100	94	6	
Total Assets	**$ 12,545**	**$ 12,686**	**$ (141)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 337	$ 338	$ (2)	
Accounts Payable - Affiliated Company	0	0	0	
Customer Deposits	50	50	1	
Derivative Liability	4	4	1	
Accrued Taxes	29	42	(13)	Higher pre-tax income.
Other Current Liabilities	142	121	21	Mostly due to $29m in payments on the last business day of the month out the A/P account which didn't have time to be funded from the Funding Account, creating negative cash in the A/P account and a liability in the credit cash adjustment account.
Total Current Liabilities	562	556	7	
Debt - Affiliated Company	-	-	-	
Debt [(1)]	4,886	4,938	(52)	Lower issuance of Commercial Paper ($52m) due to lower pension and CapEx payments.
Total Debt	4,886	4,938	(52)	
Deferred Tax Liabilities	1,065	1,117	(52)	Deferred Tax Liabilities reclassified from liability to asset as Deferred Income Taxes.
Investment Tax Credit	133	133	(0)	
Accum Provision for Pension & Related Benefits	114	120	(6)	
Asset Retirement Obligation	255	248	7	
Regulatory Liabilities	1,024	1,026	(2)	
Derivative Liability	38	32	6	
Other Liabilities	242	234	8	
Total Deferred Credits and Other Liabilities	2,872	2,911	(39)	
Equity	4,225	4,282	(57)	
Total Liabilities and Equity	**$ 12,545**	**$ 12,686**	**$ (141)**	

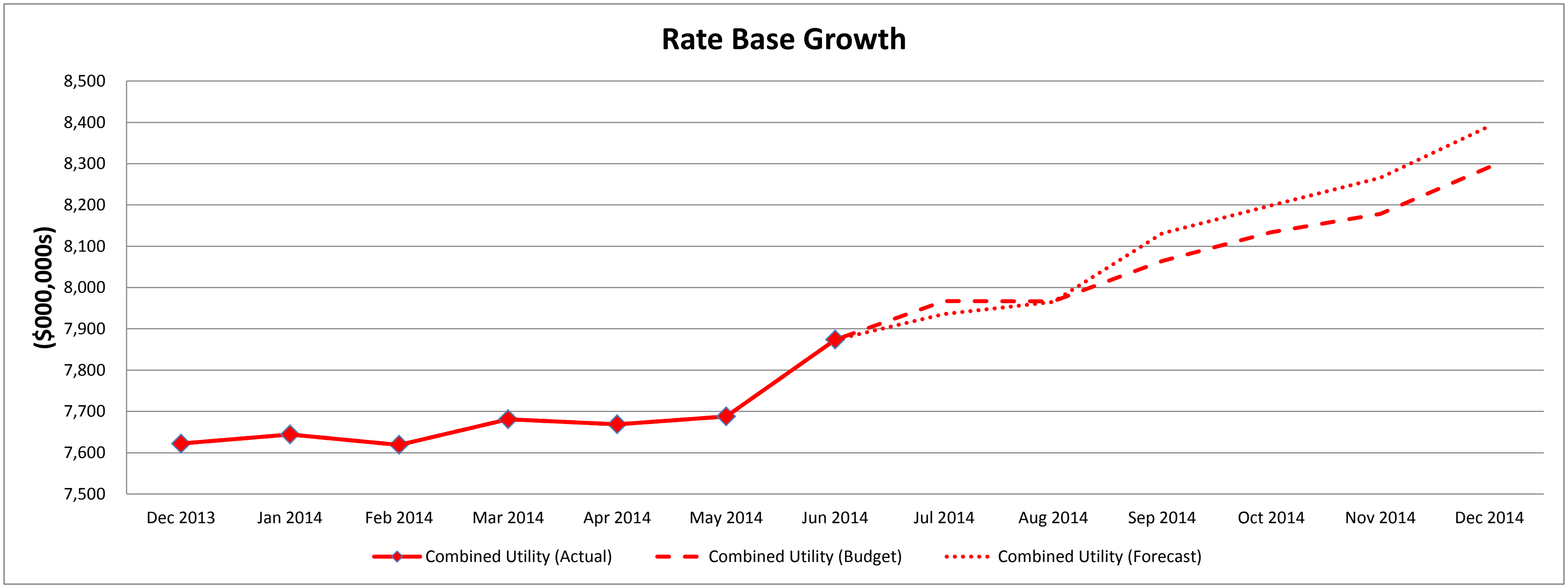
(1) Includes all ST and LT debt. See Financing Activities page for details.

Note: Schedules may not sum due to rounding.

Cash Flow

June 2014

YTD	Actual	Budget	Variance	Comments
Net Income	180	149	31	Mostly due to higher electric and gas volumes resulting from favorable weather. See income statement for more details.
Depreciation	185	179	6	
Deferred Income Taxes	149	149	0	
Other Balance Sheet Movements	(41)	(19)	(22)	See balance sheet.
Funds From Operations	**473**	**459**	**14**	
Changes in accounts receivables	13	(9)	21	Lower unbilled utility revenue offset by higher customer accounts receivable.
Changes in inventories	43	38	5	
Change in Accounts Payable	(13)	(22)	10	Higher accounts payable due to higher than expected gas purchases due to colder than normal weather.
Change in Working Capital	**43**	**7**	**36**	
Operating Cash flow	**516**	**466**	**50**	
Capex	(556)	(603)	47	Lower due primarily to timing of spending on Cane Run Unit 7, the Ohio Falls rehabilitation project, circuit hardening and gas service risers, as well as milestone shifts on Ghent environmental air projects; partially offset by higher than budgeted spending on Mill Creek environmental air projects due to delays in 2013.
Other Investing	55	0	55	LKE cash from tax settlements with PPL.
Loans to Affiliates	0	0	0	
Investing Cash flow	**(501)**	**(603)**	**102**	
Dividends	(221)	(151)	(70)	Higher due to liquidity of LKE cash related to PPL tax settlements.
Equity Infusion	119	135	(16)	Budgeted KU and LGE capital distribution but only made distribution to KU in March.
Net Borrowings	75	127	(52)	Lower issuance of CP due to lower pension payments and lower capex payments at utilities.
Other	0	0	0	
Financing Cash flow	**(27)**	**111**	**(138)**	
Net increase (decrease) in cash	**(12)**	**(26)**	**14**	


Rate Base Growth
($000,000s)
8,500
8,400
8,300
8,200
8,100
8,000
7,900
7,800
7,700
7,600
7,500
Dec 2013
Jan 2014
Feb 2014
Mar 2014
Apr 2014
May 2014
Jun 2014
Jul 2014
Aug 2014
Sep 2014
Oct 2014
Nov 2014
Dec 2014
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Forecast)

Combined KU and LG&E ROE (TTM) June 2014

KU and LG&E Combined

Reconciliation of Allowed Return to

6/30/14 Trailing Twelve Months Regulatory Return and

Book ROE from Ongoing Operations

Allowed Return [1]		10.32%	
Adjustments (net of tax):			
Change in capitalization - non ECR	-1.26%		Growth in non-ECR capitalization (rate base) between rate cases does not earn a return
Change in ROE from average mechanism rate base gr	0.00%		Mechanisms have a real-time return
Change in weighted cost of debt	-0.18%		Additional borrowings offset by favorable rates
Change in margins	2.22%		Primarily new rates since last rate cases
Change in allowed expenses	-0.75%		Inflationary increases
		0.02%	
Actual Regulated ROE		10.34%	
Adjustments (net of tax):			
Impact of non-recoverable purchase accounting	-1.94%		
Impact of 'below the line' items not recoverable through rates	-0.09%		
		-2.03%	
Actual Book ROE from Ongoing Operations		8.31%	

[1] Based on the most recent base rate filings with test years ending 3/31/12 KPSC, 12/31/12 FERC, 12/31/12 VA.

Performance Report

July 2014

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Kentucky Regulated Dashboard

July 2014

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	2.40	2.88	1.13	1.58	1.13	1.29
Employee lost-time incidents	0	0	4	1	4	3
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,023	3,462	20,593	20,311	35,092	34,780
Utility EFOR	9.6%	5.9%	5.1%	5.9%	N/A	5.9%
Utility EAF	86.8%	92.3%	80.5%	81.5%	N/A	82.5%
Steam Fleet Commercial Availability	90.7%	91.5%	93.9%	91.5%	N/A	91.5%
Combined SAIFI	0.09	0.17	0.59	0.77	N/A	1.20
Combined SAIDI (minutes)	11.37	16.81	58.71	71.69	N/A	107.60
GwH Sales						
Residential	943	1,140	6,645	6,499	11,329	10,962
Commercial	716	797	4,603	4,595	8,000	7,952
Industrial	853	912	5,766	5,741	9,946	10,011
Municipals	166	186	1,119	1,143	1,915	1,969
Other	243	267	1,654	1,610	2,832	2,788
Off-System Sales	15	14	324	209	386	273
Total	2,936	3,316	20,111	19,797	34,408	33,954
Weather-Normalized Sales Growth			**TTM**			
Residential			-0.36%			
Commercial			0.18%			
Industrial			2.20%			
Municipal			-0.39%			
Other			0.71%			
Total			0.61%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE(1)	9.6%	11.9%	10.0%	8.9%	9.1%	8.7%
Electric Margins	$147	$160	$995	$966	$1,680	$1,664
Gas Margins	8	9	96	95	158	157

Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$9	$8	$68	$89	$121	$126
ECR	$67	$56	$377	$358	$705	$603
Generation	$6	$10	$38	$51	$116	$121
Transmission	$8	$4	$49	$42	$84	$77
Electric Distribution	$12	$13	$71	$81	$146	$143
Gas Distribution	$8	$8	$39	$46	$77	$80
Customer Services	$1	$2	$9	$12	$19	$20
IT and Other	$3	$4	$17	$29	$40	$50
Total	$114	$105	$668	$708	$1,308	$1,221

O&M ($ millions)(2)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$38	$37	$279	$269	$483	$468
Administrative	7	8	$55	57	98	98
Finance	2	2	$11	11	19	19
Burdens & Other Charges	12	12	$78	88	133	150
Total	$59	$60	$423	$425	$733	$735

Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,463	3,558	3,463	3,558	3,535	3,549

Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	1	8	4	N/A	14
NERC Possible Violations(3)	1	0	4	7	N/A	11

Variance Explanations

- MTD generation volumes and GWh sales were impacted by unseasonably cool weather.

- YTD GWh sales were impacted by favorable weather earlier in the year.

- YTD capital spend lower due primarily to timing of spending on Cane Run Unit 7 and other projects.

- Full year higher capital due primarily to increased costs related to Ghent environmental air projects (Units 3 and 4 economizer work) and Mill Creek environmental air projects (Units 1, 2 and 4 fabric filters and wet flue gas desulfurization units) with some non-environmental spend offsets due to cost reductions.

- MTD lower margins driven by unseasonably mild weather resulting in $15 million lower retail electric energy and demand charge revenues which were partially offset by $1 million from favorable cost of production expenses.

- YTD higher margins due to $14 million higher retail electric energy and demand revenues resulting from favorable weather earlier this year, $8 million from the sale of excess generation driven by favorable plant availability and higher market prices, $5 million from lower cost of production margin expenses and $3 million from lower purchase power demand costs.

Major Developments

- LKE announced it will withdraw its proposal to build a new natural gas combined-cycle generating unit at Green River, however, will continue with plans to build a 10 megawatt solar generation facility at E.W. Brown. The decision is based upon revised estimates of future capacity timing requirements for LG&E and KU following the election by certain of KU's municipal customers to terminate their wholesale power contracts in 2019. The $700 million Green River 5 project was included in the 2014 Business Plan.

- In a significant development for LKE and PPL, U.S. District Court Judge Joseph McKinley eliminated several of the plaintiffs' claims in the Cane Run lawsuit. The court case was not completely dismissed, however, the judge rejected all but one of the statutory citizen suit claims by the group of neighbors, while still allowing the state-law tort case against LKE. LKE will continue to defend this matter vigorously.

- LKE marked another milestone in its efforts to comply with environmental regulations as the Kentucky Division of Waste Management issued a permit for construction of the Brown landfill. Charah, the selected contractor, has mobilized on-site and construction activities are underway as planned.

- LKE hosted a ceremony recognizing the construction of Kentucky's first megawatt scale carbon capture slipstream pilot plant to be installed at Brown Station. In collaboration with the University of Kentucky Center for Applied Energy Research, the $19.5 million project is expected to be completed later this year and testing will conclude in 2016.

- Both Louisville and Lexington have been impacted by mild weather, and July 2014 ranked as the 2nd and 4th coolest, respectively, in the past 20 years.

Significant Future Events

- Heavy construction is proceeding at Mill Creek, Ghent, Brown and Cane Run. All projects are expected to be in service by target completion dates. Mill Creek Unit 4 work is on schedule for the tie-in outage set for the fourth quarter of this year and engineering activities are underway for the Trimble County 1 fabric filter.

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(1) Excludes goodwill and other purchase accounting adjustments.
(2) Net of cost recovery mechanisms.
(3) The possible violation issues for YTD Actual are believed to be minimal risk and are expected to receive a zero dollar penalty from the regulator.

Income Statement: Actual vs. Budget and Forecast (Month) July 2014

($ Millions)

	MTD				MTD			
	Actual	Budget	Variance	Comments	Actual	Q2 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 243	$ 274	$ (31)	Due to lower electricity volumes resulting from unfavorable weather.	$ 243	$ 267	$ (23)	Due to lower electricity volumes resulting from unfavorable weather.
Gas Revenues	12	12	0		12	12	(1)	
Total Revenues	255	286	(30)		255	279	(24)	
Cost of Sales:								
Fuel Electric Costs	83	96	13	Due to lower electricity volumes resulting from unfavorable weather.	83	97	14	Due to lower electricity volumes resulting from unfavorable weather.
Gas Supply Expenses	4	3	(1)		4	4	0	
Purchased Power	4	6	2		4	6	2	
Other Electric Cost	10	11	2		10	11	1	
Total Cost of Sales	101	117	16		101	118	17	
Gross Margin:								
Electric Margin	147	160	(13)	Due to lower electricity volumes resulting from unfavorable weather.	147	153	(6)	Due to lower electricity volumes resulting from unfavorable weather.
Gas Margin	8	9	(1)		8	8	(0)	
Total Gross Margin	155	169	(14)		155	161	(6)	
Operating Expenses:								
O&M	59	60	1		59	61	2	
Depreciation & Amortization	29	29	0		29	29	0	
Taxes, Other than Income	4	4	(0)		4	4	0	
Total Operating Expenses	92	93	1		92	94	2	
Other income	(0)	(0)	(0)		(0)	(0)	(0)	
EBIT	63	76	(13)		63	67	(4)	
Interest Expense	14	14	0		14	14	0	
Income from Ongoing Operations before income taxes	48	62	(13)		48	53	(4)	
Income Tax Expense	18	23	5		18	20	2	
Net Income (loss) from ongoing operations	**$ 30**	**$ 38**	**$ (8)**		**$ 30**	**33**	**$ (3)**	
Non Operating Income	0	0	0		0	0	0	
Discontinued Operations	0	0	(0)		0	0	(0)	
Net Income (loss)	$ 30	$ 38	$ (8)		$ 30	$ 33	$ (3)	
KY Regulated Financing Costs	(3)	(3)	0		(3)	(3)	-	
KY Regulated Net Income	$ 28	$ 36	$ (8)		$ 28	$ 30	$ (3)	
Earnings Per Share	$ 0.04	$ 0.05	$ (0.01)		$ 0.04	$ 0.04	$ (0.00)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) July 2014

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,683	$ 1,632	$ 51	Due to higher electricity volumes resulting from favorable weather earlier this year.
Gas Revenues	$ 232	196	36	Due to higher gas volumes resulting from favorable weather earlier this year.
Total Revenues	$ 1,915	1,828	87	
Cost of Sales:				
Fuel Electric Costs	594.80	555	(39)	Due to higher electricity volumes resulting from favorable weather earlier this year.
Gas Supply Expenses	136.19	101	(35)	Due to higher gas volumes resulting from favorable weather earlier this year.
Purchased Power	32.67	41	8	Due to lower purchases than planned.
Other Electric Cost	60.49	70	10	Due primarily to lower plant system consumables costs.
Total Cost of Sales	824.36	767	(57)	
Gross Margin:				
Electric Margin	995	966	29	Higher margins driven by favorable weather and system availability earlier this year.
Gas Margin	96	95	1	
Total Gross Margin	1,091	1,061	30	
Operating Expenses:				
O&M	423	425	2	
Depreciation & Amortization	198	200	2	
Taxes, Other than Income	30	30	0	
Total Operating Expenses	650	655	4	
Other income	(5)	(5)	0	
EBIT	436	401	35	
Interest Expense	97	100	3	
Income from Ongoing Operations before income taxes	338	301	38	
Income Tax Expense	128	113	(15)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**$ 210**	**$ 188**	**$ 23**	
Non Operating Income	0	-	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 211	$ 188	$ 23	
KY Regulated Financing Costs	(18)	(18)	(0)	
KY Regulated Net Income	$ 192	$ 170	$ 23	
Earnings Per Share	$ 0.29	$ 0.25	$ 0.03	

Note: Schedules may not sum due to rounding.

Income Statement: Forecast vs. Prior Forecast & Budget

July 2014

($ Millions)

	Full Year				Full Year			
	Q2 Forecast	Q1 Forecast	Variance	Comments	Q2 Forecast	Budget	Variance	Comments
Revenues:								
Electric Revenues	$ 2,873	$ 2,877	$ (4)		$ 2,873	$ 2,815	$ 58	Due to higher electricity volumes resulting from favorable weather.
Gas Revenues	355	351	4		355	318	36	Due to higher gas volumes resulting from colder than normal weather.
Total Revenues	3,228	3,227	0		3,228	3,134	94	
Cost of Sales:								
Fuel Electric Costs	1,011	996	(15)	Due to higher electricity volumes resulting from favorable weather.	1,011	953	(58)	Due to higher electricity volumes resulting from favorable weather.
Gas Supply Expenses	197	193	(4)	Due to higher electricity volumes resulting from favorable weather.	197	162	(36)	Due to higher gas volumes resulting from colder than normal weather.
Purchased Power	66	69	3		66	72	6	Due to lower purchases than planned.
Other Electric Cost	117	124	7	Due primarily to lower plant system consumables costs.	117	127	10	Due primarily to lower plant system consumables costs.
Total Cost of Sales	1,390	1,381	(9)		1,390	1,313	(77)	
Gross Margin:								
Electric Margin	1,680	1,689	(9)	Due to higher cost of sales (see above).	1,680	1,664	16	Due to higher revenues offset by higher cost of sales (see above).
Gas Margin	158	158	0		158	157	1	
Total Gross Margin	1,837	1,846	(9)		1,837	1,820	17	
Operating Expenses:								
O&M	733	742	9	Due primarily to lower pension and medical related expenses.	733	735	2	
Depreciation & Amortization	342	343	1		342	344	2	
Taxes, Other than Income	51	51	(0)		51	51	(0)	
Total Operating Expenses	1,126	1,135	9		1,126	1,130	3	
Other income	(7)	(6)	(0)		(7)	(7)	0	
EBIT	704	705	(0)		704	684	20	
Interest Expense	170	171	1		170	172	3	
Income from Ongoing Operations before income taxes	534	533	1		534	511	23	
Income Tax Expense	202	200	(2)		202	192	(9)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**$ 333**	**$ 333**	**$ 0**		**$ 333**	**$ 319**	**$ 13**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	0	0	(0)		0	0	(0)	
Net Income (loss)	$ 333	$ 334	$ (1)		$ 333	$ 320	$ 14	
KY Regulated Financing Costs	(31)	(31)	0		(31)	(31)	0	
KY Regulated Net Income	$ 302	$ 302	$ (0)		$ 302	$ 288	$ 14	
Earnings Per Share	$ 0.45	$ 0.45	$ 0.00		$ 0.45	$ 0.43	$ 0.02	

Note: Schedules may not sum due to rounding.

Electric Gross Margin

July 2014

($ Millions)

	MTD						YTD					
	Actual	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**	**Actual**	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**
Base Electric Margin:						♦ **$ (15)**						🟢 **$ 14**
Energy Volumes (a)	2,920,586	3,302,862	(382,276)	$ -	$ (13)		19,786,849	19,588,691	198,159	$ -	$ 8	
Energy Prices (a)					(0)						1	
Customer Charges (Avg. Customers)	938,142	948,641	(10,499)		-		939,250	946,101	(6,851)		(0)	
Demand Charges (b)	43	45			(2)		278	273			5	
ECR:						🟢 **$ 0**						♦ **$ (0)**
Average Rate Base	$ 1,451	$ 1,402	$ 50	10.37%	$ 0.4		$ 1,283	$ 1,258	$ 25	10.38%	$ 1.3	
Cost of Capital	10.10%	10.37%	-0.27%	$ 1,451	$ (0.3)		10.18%	10.38%	-0.20%	$ 1,283	(1.3)	
Jurisdictional Factor	91.49%	90.22%	1.27%	$ 1,451	$ 0.2		87.65%	87.93%	-0.28%	$ 1,283	(0.2)	
Other					$ 0.1						0.1	
DSM:						♦ **$ (0)**						♦ **$ (2)**
Program Expense (Revenue Net of Expense)	$ 0.1	$ 0.1			$ -		$ (0.1)	$ 0.3			$ (0.4)	
Lost Sales	1.6	1.9			$ (0.3)		11.8	13.0			(1.2)	
Incentive	0.1	0.1			$ -		0.7	0.6			0.1	
Balancing Adjustment	-	-			$ -		(0.3)	-			(0.3)	
Net Fuel Recovery	$ (0.6)	$ (0.6)				🟢 **$ -**	$ (4)	$ (3)				♦ **$ (1)**
Purchase Power Demand	(1.7)	(2.6)				🟢 **$ 1**	(14.4)	(17.9)				🟢 **$ 3**
Transmission	0.9	1.2				♦ **$ (0)**	6.8	6.4				🟢 **$ 1**
Other	(2.1)	(2.8)				🟢 **$ 1**	(9.6)	(14.8)				🟢 **$ 5**
Retail Margin Variance						♦ **$ (13)**						🟢 **$ 21**
Off-System Margin Variance						🟢 **$ -**						🟢 **$ 8**
Electric Margin Variance						♦ **$ (13)**						🟢 **$ 29**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			**Budget**			**Variance**		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 46	943,317	$ 49.07	$ 56	1,140,113	$ 49.10	♦ ($10)	♦ ($10)	🟢 $0
Commercial	22	715,927	30.59	26	797,323	32.06	♦ ($4)	♦ ($3)	♦ ($1)
Industrial	8	853,057	9.05	8	912,514	9.04	♦ ($1)	♦ ($1)	🟢 $0
Municipals	1	165,754	4.40	1	185,918	4.16	♦ ($0)	♦ ($0)	🟢 $0
Other	5	242,529	20.66	5	266,994	16.98	🟢 $1	♦ ($0)	🟢 $1
Native Load Total	**$ 82**	**2,920,586**	**$ 27.96**	**$ 95**	**3,302,862**	**$ 28.79**	♦ **($14)**	♦ **($13)**	♦ **($0)**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			**Budget**			**Variance**		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 324	6,645,645	$ 48.71	$ 317	6,498,892	$ 48.83	🟢 $6	🟢 $7	♦ ($1)
Commercial	143	4,602,161	31.00	148	4,595,438	32.27	♦ ($6)	🟢 $0	♦ ($6)
Industrial	52	5,766,091	8.98	52	5,741,415	8.97	🟢 $0	🟢 $0	🟢 $0
Municipals	6	1,119,214	5.20	6	1,142,541	5.34	♦ ($0)	♦ ($0)	♦ ($0)
Other	38	1,653,739	22.78	29	1,610,406	18.16	🟢 $9	🟢 $1	🟢 $8
Native Load Total	**$ 562**	**19,786,849**	**$ 28.38**	**$ 552**	**19,588,691**	**$ 28.20**	🟢 **$9**	🟢 **$8**	🟢 **$1**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD			YTD		
	Act	**Bud**	**Variance**	**Act**	**Bud**	**Variance**
Commercial	15	15	(0)	95	89	6
Industrial	17	18	(1)	113	116	(3)
Municipals	5	5	(1)	30	30	(0)
Other	6	6	(0)	40	38	2
Native Load Total	**43**	**45**	**(2)**	**278**	**273**	**5**

Gas Gross Margin July 2014

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		🟢 **$ -**	**$ 35**	**$ 35**		🟢 **$ 0**
Gas Supply Costs								
Gas Supply Costs	(4)	(3)	$ (1)		(135)	(99)	$ (36)	
GSC Revenue	4	3	1		133	99	34	
Net Gas Supply Costs				♦ **$ (0)**				♦ **$ (2)**
Retail Gas (a)	**2**	**2**		♦ **$ (0)**	**62**	**54**		🟢 **$ 8**
Wholesale Gas (a)	**-**	**-**		🟢 **$ -**	**-**	**-**		🟢 **$ -**
DSM	**(0)**	**0**		♦ **$ (0)**	**0**	**0**		♦ **$ (0)**
GLT	**1**	**1**		🟢 **$ 0**	**4**	**5**		♦ **$ (1)**
WNA	**-**	**-**		🟢 **$ -**	**(6)**	**-**		♦ **$ (6)**
Other Margin	**0**	**0**		🟢 **$ -**	**1**	**1**		🟢 **$ 0**
Gas Margin Variance				♦ **$ (1)**				🟢 **$ 1**

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 1	316,587	$ 2.64	$ 1	379,758	$ 2.64	♦ ($0)	♦ $ (0)	🟢 $ -
Commercial	1	263,061	1.92	1	265,238	2.08	♦ ($0)	🟢 $ -	🟢 $ -
Industrial	0	114,514	1.32	0	48,546	1.77	🟢 $0	🟢 $ 0	♦ $ (0)
Public Authority	0	39,234	1.52	0	33,608	1.93	🟢 $0	🟢 $ -	🟢 $ -
Transportation	1	819,023	0.97	0.70	916,083	0.79	🟢 $0	♦ $ (0)	🟢 $ 0
Ultimate Consumer	$ 2	1,552,419	$ 1.51	$ 2	1,643,233	$ 1.48	♦ ($0)	♦ $ (0)	🟢 $ -

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 38	14,373,829	$ 2.64	$ 33	12,590,075	$ 2.64	🟢 $5	🟢 $ 5	🟢 $ -
Commercial	14	6,613,692	2.04	12	5,603,935	2.08	🟢 $2	🟢 $ 2	♦ $ (0)
Industrial	1	829,262	1.75	1	600,223	1.78	🟢 $0	🟢 $ 0	🟢 $ -
Public Authority	2	1,036,641	1.97	2	960,884	2.01	🟢 $0	🟢 $ 0	🟢 $ -
Transportation	7	8,401,987	0.81	6	7,655,028	0.79	🟢 $1	🟢 $ 1	🟢 $ 0
Ultimate Consumer	$ 62	31,255,411	$ 1.98	$ 54	27,410,145	$ 1.97	🟢 $8	🟢 $ 8	♦ $ (0)

O&M July 2014

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 17	$ 17	$ (0)	$ 0	$ (0)	$ (1)	$ 1		$ 0
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	3	3	(0)	0		(1)	0		0
Energy Supply and Analysis	1	1	0	0		0	0		0
Electric Distribution	7	6	(1)	(0)		(0)	0	(0)	(0)
Gas Distribution	3	3	0	0		(0)	0	(0)	0
Safety and Security	0	0	(0)	(0)		(0)	0	0	(0)
Customer Services	7	7	0	0		0	0	(0)	(0)
Chief Operations Officer	**38**	**37**	**(1)**	**0**	**(0)**	**(2)**	**1**	**(0)**	**0**
Information Technology	4	5	1	0		0	(0)		0
General Counsel	2	2	(0)	0		(0)	0		(0)
Human Resources	1	1	0	0		0	0		0
Supply Chain	0	0	0	0		(0)	0		0
Chief Administrative Officer	**7**	**8**	**1**	**1**		**0**	**(0)**		**(0)**
Chief Financial Officer	**2**	**2**	**0**	**0**		**(0)**	**0**		**0**
Corporate	**12**	**12**	**1**	**1**		**0**	**0**		**(0)**
O&M Total MTD	**$ 59**	**$ 60**	**$ 1**	**$ 2**	**$ (0)**	**$ (2)**	**$ 1**	**$ (0)**	**$ 0**

	YTD								
	Actual	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 139	$ 139	$ 0	$ 3	$ 0	$ (3)	$ 1		$ (1)
Project Engineering	0	0	0	0		(0)	(0)		0
Transmission	17	17	0	(0)		(1)	1		0
Energy Supply and Analysis	5	5	0	0		0	0		0
Electric Distribution	49	43	(6)	(1)		(5)	0	(0)	(1)
Gas Distribution	18	18	0	(0)		1	0	(0)	(0)
Safety and Security	2	0	(2)	(1)		(0)	0	0	(0)
Customer Services	48	45	(3)	0		(1)	0	(2)	(0)
Chief Operations Officer	**279**	**269**	**(10)**	**1**	**0**	**(9)**	**2**	**(2)**	**(2)**
Information Technology	30	32	2	2		1	(0)		(0)
General Counsel	18	18	(1)	0		(1)	0		(0)
Human Resources	4	5	1	0		0	0		0
Supply Chain	2	2	0	0		(0)	(0)		0
Chief Administrative Officer	**55**	**57**	**2**	**3**		**(0)**	**(0)**		**(0)**
Chief Financial Officer	**11**	**11**	**0**	**0**		**0**	**0**		**(0)**
Corporate	**78**	**88**	**10**	**10**		**2**	**1**	**(0)**	**(4)**
O&M Total YTD	**$ 423**	**$ 425**	**$ 2**	**$ 14**	**$ 0**	**$ (7)**	**$ 3**	**$ (2)**	**$ (6)**

	Full Year								
	Forecast	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 244	$ 245	$ 1	$ 3	$ 1	$ (4)	$ 1		$ (1)
Project Engineering	1	1	0	(0)		(0)	(0)		0
Transmission	29	29	(1)	(0)		0	(1)		0
Energy Supply and Analysis	9	9	0	0		0	0		0
Electric Distribution	77	72	(5)	0		(4)	0	0	(1)
Gas Distribution	32	32	(0)	(0)		0	0	0	(0)
Safety and Security	3	0	(3)	(3)		(0)	0	0	(0)
Customer Services	87	79	(8)	(0)		(3)	0	(5)	(1)
Chief Operations Officer	**483**	**468**	**(16)**	**0**	**1**	**(10)**	**1**	**(5)**	**(3)**
Information Technology	55	55	0	1		(0)	(0)		(0)
General Counsel	32	32	0	(0)		0	0		(0)
Human Resources	8	8	0	0		0	0		0
Supply Chain	4	4	(0)	(0)		0	0		0
Chief Administrative Officer	**98**	**98**	**1**	**1**		**(0)**	**(0)**		**(0)**
Chief Financial Officer	**19**	**19**	**0**	**0**		**0**	**0**		**(0)**
Corporate	**133**	**150**	**17**	**19**		**1**	**(0)**	**(0)**	**(3)**
O&M Total Full Year	**$ 733**	**$ 735**	**$ 2**	**$ 20**	**$ 1**	**$ (9)**	**$ 1**	**$ (5)**	**$ (5)**

Note: Schedules may not sum due to rounding.

Financing Activities July 2014

($ Millions)

	MTD			YTD			Full Year		
Balance Sheet	**Actual**	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**	**Forecast**	**Budget**	**Variance**
PCB									
Beg Bal	$ 924.0	$ 924.5	$ 0.5	$ 924.0	$ 924.0	$ 0.0	$ 924.0	$ 924.0	$ -
End Bal	924.0	924.6	0.6	924.0	924.6	0.6	925.8	924.9	(0.8)
Ave Bal	**$ 924.0**	**$ 924.5**	**$ 0.6**	**$ 924.0**	**$ 924.4**	**$ 0.4**	**$ 924.5**	**$ 924.6**	**$ 0.1**
Interest Exp	**$ 0.8**	**$ 0.9**	**$ 0.2**	**$ 5.4**	**$ 6.6**	**$ 1.3**	**$ 10.3**	**$ 11.3**	**$ 1.1**
Rate	**0.94%**	**1.19%**	**0.24%**	**0.98%**	**1.22%**	**0.23%**	**1.11%**	**1.23%**	**0.12%**
FMB/Sr Nts									
Beg Bal	$ 3,641.8	$ 3,641.7	$ (0.1)	$ 3,640.9	$ 3,640.9	$ -	$ 3,640.9	$ 3,640.9	$ -
End Bal	3,641.9	3,641.8	(0.1)	3,641.9	3,641.8	(0.1)	3,642.6	3,642.5	(0.1)
Ave Bal	**$ 3,641.8**	**$ 3,641.8**	**$ (0.1)**	**$ 3,641.4**	**$ 3,641.4**	**$ 0.0**	**$ 3,641.8**	**$ 3,641.8**	**$ (0.0)**
Interest Exp	**$ 11.5**	**$ 11.6**	**$ 0.1**	**$ 80.5**	**$ 81.5**	**$ 1.0**	**$ 140.5**	**$ 141.4**	**$ 0.8**
Rate	**3.66%**	**3.71%**	**0.05%**	**3.75%**	**3.80%**	**0.05%**	**3.86%**	**3.88%**	**0.02%**
Short-term Debt									
Beg Bal	$ 320.0	$ 371.7	$ 51.7	$ 245.0	$ 245.0	$ -	$ 245.0	$ 245.0	$ -
End Bal	316.0	369.5	53.5	316.0	369.5	53.5	570.9	527.8	(43.1)
Ave Bal	**$ 318.0**	**$ 370.6**	**$ 52.6**	**$ 280.5**	**$ 290.8**	**$ 10.3**	**$ 357.6**	**$ 356.8**	**$ (0.8)**
Interest Exp	**$ 0.2**	**$ 0.3**	**$ 0.1**	**$ 1.2**	**$ 1.9**	**$ 0.7**	**$ 3.1**	**$ 3.6**	**$ 0.5**
Rate	**0.70%**	**0.93%**	**0.24%**	**0.73%**	**1.10%**	**0.37%**	**0.87%**	**1.00%**	**0.14%**
Total End Bal	**$ 4,881.9**	**$ 4,935.9**	**$ 54.0**	**$ 4,881.9**	**$ 4,935.9**	**$ 54.0**	**$ 5,139.3**	**$ 5,095.3**	**$ (44.0)**
Total Average Bal	**$ 4,883.8**	**$ 4,936.9**	**$ 53.1**	**$ 4,845.8**	**$ 4,856.6**	**$ 10.7**	**$ 4,923.9**	**$ 4,923.2**	**$ (0.7)**
Total Expense Excl I/C (1)	**$ 13.9**	**$ 14.4**	**$ 0.4**	**$ 97.3**	**$ 100.4**	**$ 3.0**	**$ 169.7**	**$ 172.4**	**$ 2.7**
Rate	**3.32%**	**3.38%**	**0.06%**	**3.41%**	**3.51%**	**0.10%**	**3.45%**	**3.50%**	**0.05%**

(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**	**Letters of Credit Issued**	**Unused Capacity**
LKE	$ 300	$ 75		$ 225
LG&E	500	81		419
KU	598	160	$ 198	240
TOTAL	$ 1,398	$ 316	$ 198	$ 884

Credit Metrics	**YTD**		**Full Year**	
($ Millions)	**Actual**	**+/- Bud**	**Forecast**	**+/- Bud**
FFO to Debt - LG&E	26.5%	+0.01	20.9%	-0.02
FFO to Debt - KU	26.0%	+0.02	22.4%	-0.02
Debt to EBITDA - LG&E (2)	3.08	-0.59	3.57	-0.09
Debt to EBITDA - KU (2)	3.56	-0.16	3.65	-0.07
Debt to Capitalization - LG&E (3)	46.3%	+0.00	47.0%	+0.00
Debt to Capitalization - KU (3)	46.9%	-0.01	47.0%	+0.00

(2) Actuals represent a trailing 12 months

(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

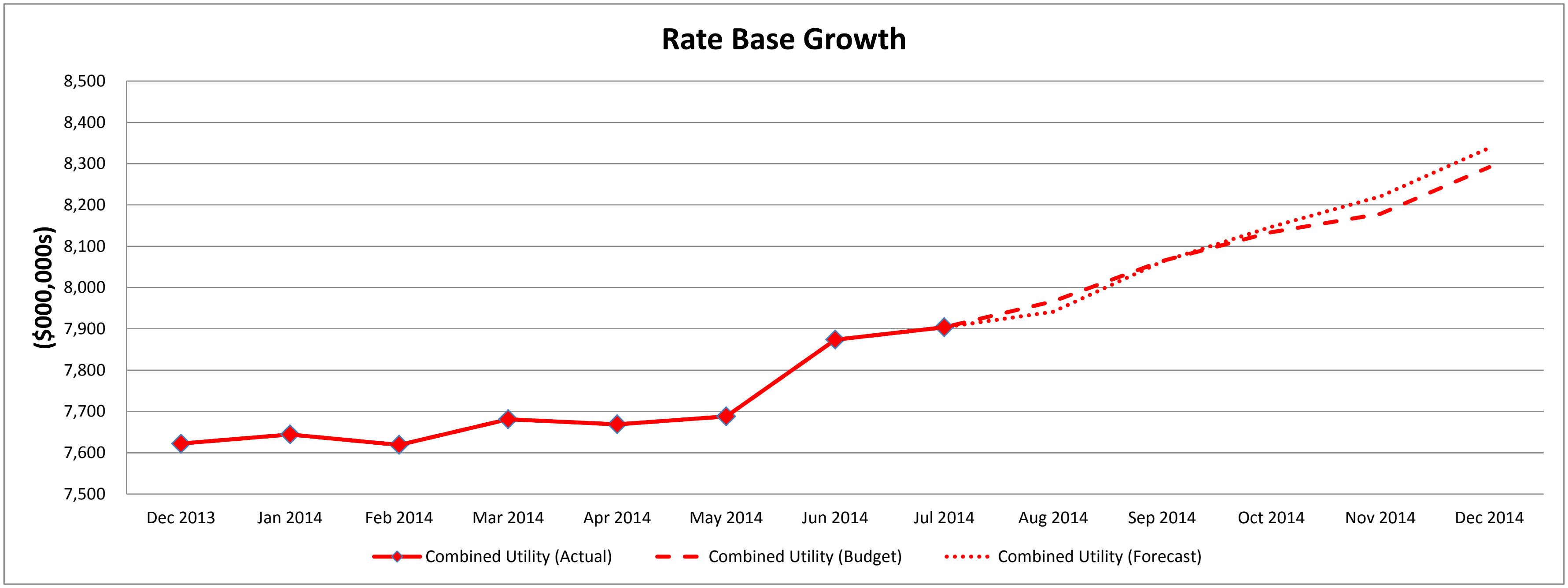
Balance Sheet — July 2014

($ Millions)

	7/31/2014	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 18	$ 9	$ 9	
Accounts Receivable (Trade)	384	419	(36)	Lower unbilled utility revenue ($40m) offset by higher customer accounts receivable $6m.
Inventory	245	244	1	
Deferred Income Taxes	108	159	(51)	Deferred Income Taxes reclassified from asset to liability Deferred Tax Liabilities.
Prepayments and other current assets	73	115	(42)	Lower notes receivable from affiliate ($44m).
Total Current Assets	828	947	(119)	
Property, Plant, and Equipment	10,010	10,049	(39)	Lower CWIP ($33m).
Intangible Assets	193	194	(0)	
Other Property and Investments	1	1	(0)	
Regulatory Assets	496	489	7	
Goodwill	997	997	0	
Other Long-term Assets	102	93	9	
Total Assets	**$ 12,627**	**$ 12,769**	**$ (142)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 375	$ 345	$ 30	Increases in project engineering $15m and gas purchase $5m accruals and increase in and timing of coal receipts $14m.
Accounts Payable - Affiliated Company	0	0	0	
Customer Deposits	51	50	1	
Derivative Liability	4	4	1	
Accrued Taxes	49	70	(21)	Lower pre-tax income.
Other Current Liabilities	136	136	(1)	
Total Current Liabilities	614	605	10	
Debt - Affiliated Company	-	-	-	
Debt [1]	4,882	4,936	(54)	Lower issuance of Commercial Paper ($54m) due to lower pension and CapEx payments.
Total Debt	4,882	4,936	(54)	
Deferred Tax Liabilities	1,065	1,117	(52)	Deferred Tax Liabilities reclassified from liability to asset as Deferred Income Taxes.
Investment Tax Credit	132	132	(0)	
Accum Provision for Pension & Related Benefits	115	121	(6)	
Asset Retirement Obligation	256	249	7	
Regulatory Liabilities	1,024	1,023	2	
Derivative Liability	37	32	5	
Other Liabilities	245	235	10	Accrued retiree medical post employee benefits $6m which are not budgeted for in the Other Liabilities account. In December the balance is moved to the liability account where it is budgeted for.
Total Deferred Credits and Other Liabilities	2,875	2,909	(33)	
Equity	4,256	4,320	(65)	
Total Liabilities and Equity	**$ 12,627**	**$ 12,769**	**$ (142)**	

[1] Includes all ST and LT debt. See Financing Activities page for details.

Note: Schedules may not sum due to rounding.


Rate Base Growth
($000,000s)
8,500
8,400
8,300
8,200
8,100
8,000
7,900
7,800
7,700
7,600
7,500
Dec 2013
Jan 2014
Feb 2014
Mar 2014
Apr 2014
May 2014
Jun 2014
Jul 2014
Aug 2014
Sep 2014
Oct 2014
Nov 2014
Dec 2014
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Forecast)

Performance Report

August 2014

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Kentucky Regulated Dashboard

August 2014

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.63	0.34	1.24	1.41	1.24	1.29
Employee lost-time incidents	0	0	4	1	4	3
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	3,202	3,473	23,795	23,784	34,821	34,780
Utility EFOR	3.6%	5.9%	4.9%	5.9%	N/A	5.9%
Utility EAF	93.7%	92.3%	82.2%	82.8%	N/A	82.5%
Steam Fleet Commercial Availability	93.8%	91.5%	93.9%	91.5%	N/A	91.5%
Combined SAIFI	0.10	0.12	0.69	0.89	N/A	1.20
Combined SAIDI (minutes)	8.94	9.21	67.64	80.90	N/A	107.60
GwH Sales						
Residential	1,010	1,132	7,655	7,631	11,329	10,962
Commercial	732	798	5,335	5,393	8,000	7,952
Industrial	892	943	6,658	6,684	9,946	10,011
Municipals	175	191	1,294	1,334	1,915	1,969
Other	261	267	1,915	1,877	2,832	2,788
Off-System Sales	40	8	364	217	386	273
Total	3,110	3,339	23,221	23,136	34,408	33,954
Weather-Normalized Sales Growth			**TTM**			
Residential			-0.06%			
Commercial			-0.17%			
Industrial			2.37%			
Municipal			0.02%			
Other			1.83%			
Total			0.79%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[1]	11.8%	12.1%	10.2%	9.3%	9.1%	8.7%
Electric Margins	$154	$161	$1,149	$1,127	$1,680	$1,664
Gas Margins	$8	8	104	103	158	157
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$5	$8	$72	$97	$121	$126
ECR	$73	$55	$450	$413	$705	$603
Generation	$6	$12	$44	$63	$116	$121
Transmission	$6	$7	$55	$49	$84	$77
Electric Distribution	$16	$13	$87	$94	$146	$143
Gas Distribution	$8	$8	$47	$54	$78	$80
Customer Services	$2	$2	$11	$14	$19	$20
IT and Other	$3	$4	$20	$33	$39	$50
Total	$119	$108	$787	$816	$1,307	$1,221
O&M ($ millions)[2]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$36	$37	$315	$306	$483	$468
Administrative	8	8	$63	65	98	98
Finance	2	2	$12	13	19	19
Burdens & Other Charges	8	12	$86	100	133	150
Total	$54	$59	$476	$483	$733	$735
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,453	3,561	3,453	3,561	3,531	3,549
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	1	3	9	7	N/A	14
NERC Possible Violations[3]	1	2	5	9	N/A	11

Variance Explanations

- Current month generation volumes and GWh sales were impacted by unseasonably cool weather.

- YTD capital spend lower due primarily to timing of spending on Cane Run Unit 7 and other projects.

- Full year higher capital due primarily to increased costs related to Ghent environmental air projects (Units 3 and 4 economizer work) and Mill Creek environmental air projects (Units 1, 2 and 4 fabric filters and wet flue gas desulfurization units) with some non-environmental spend offsets due to cost reductions.

- Current month lower margins driven by unseasonably mild weather resulting in $11 million lower retail electric energy and demand charge revenues which were partially offset by $2 million from favorable cost of production expenses and $2 million from higher retail rate mechanism revenue.

- YTD higher margins due to $3 million higher retail electric energy and demand revenues, $8 million from the sale of excess generation driven by favorable plant availability and higher market prices, $5 million from lower cost of production margin expenses, $4 million from lower purchase power demand costs, and $3 million from higher gas margins and other revenues.

- Current month lower O&M primarily due to $4 million of labor and benefit savings and $1 million of materials expense savings.

- YTD lower O&M primarily due to $15 million of labor and benefit savings and $2 million lower material and other expenses partially offset by $7 million of higher storms expenses and $3 million higher uncollectible accounts.

Major Developments

- In order to meet planned reserve margins beginning in 2015 and extending through 2019, LKE executed a Tolling Agreement for Unit 3 at the Bluegrass Generation Station in Oldham County, KY. The agreement contains 165MWs of additional capacity from May 1, 2015 through April 30, 2019. This contract was assumed in the 2014 Business Plan.

- For the third consecutive year, LKE has been named one of the top 10 utilities in economic development by Site Selection magazine. The winners were chosen based on multiple criteria related to 2013 activity. LKE's efforts helped companies create 10,303 jobs and invest $2.6 billion in facility location or expansion projects.

- An Informal Conference was held with the KPSC and the Interveners regarding the Brown Solar CPCN case. Although nothing was finalized from the meeting, all parties are agreeable to consider a settlement.

- The DSM hearing concluded with all parties agreeing to file simultaneous briefs on September 30. This proceeding included LKE plans to expand and enhance five DSM programs for 2015 -2018, and offer up to 10,000 customers a smart meter on a voluntary basis.

Significant Future Events

- Heavy construction is proceeding at Mill Creek, Ghent, Brown, Cane Run and Trimble County. All projects are expected to be in service by target completion dates. Mill Creek Unit 4 and Ghent 4 tie-in outages are scheduled to occur during the fourth quarter of this year.

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(1) Excludes goodwill and other purchase accounting adjustments.

(2) Net of cost recovery mechanisms.

(3) The possible violation issues for YTD Actual are believed to be minimal risk and are expected to receive a zero dollar penalty from the regulator.

Income Statement: Actual vs. Budget and Forecast (Month) — August 2014

($ Millions)

	MTD				MTD			
	Actual	Budget	Variance	Comments	Actual	Q2 Forecast	Variance	Comments
Revenues:								
Electric Revenues	$ 254	$ 277	$ (23)	Due to lower electricity volumes resulting from unfavorable weather.	$ 254	$ 268	$ (15)	Due to lower electricity volumes resulting from unfavorable weather.
Gas Revenues	13	12	1		13	12	1	
Total Revenues	267	289	(22)		267	280	(14)	
Cost of Sales:								
Fuel Electric Costs	86	97	10	Due to lower electricity volumes resulting from unfavorable weather.	86	97	10	Due to lower electricity volumes resulting from unfavorable weather.
Gas Supply Expenses	4	4	(1)		4	4	(1)	
Purchased Power	4	6	2		4	6	2	
Other Electric Cost	9	13	3		9	12	3	
Total Cost of Sales	104	119	15		104	119	15	
Gross Margin:								
Electric Margin	154	161	(7)	Due to lower electricity volumes resulting from unfavorable weather.	154	154	1	
Gas Margin	8	8	(0)		8	8	0	
Total Gross Margin	162	169	(7)		162	162	1	
Operating Expenses:								
O&M	54	59	5	Due primarlity to labor and benefit savings.	54	59	5	Due primarlity to labor and benefit savings.
Depreciation & Amortization	29	29	0		29	29	0	
Taxes, Other than Income	4	4	(0)		4	4	0	
Total Operating Expenses	87	92	5		87	92	5	
Other income	(1)	(0)	(0)		(1)	(0)	(0)	
EBIT	75	77	(2)		75	69	6	
Interest Expense	14	14	0		14	14	0	
Income from Ongoing Operations before income taxes	61	63	(2)		61	55	6	
Income Tax Expense	23	24	1		23	21	(2)	
Net Income (loss) from ongoing operations	**38**	**39**	**$ (1)**		**$ 38**	**34**	**$ 4**	
Non Operating Income	(0)	0	(0)		(0)	0	(0)	
Discontinued Operations	(0)	0	(0)		(0)	0	(0)	
Net Income (loss)	$ 38	$ 39	$ (1)		$ 38	$ 34	$ 4	
KY Regulated Financing Costs	(3)	(3)	0		(3)	(3)	-	
KY Regulated Net Income	$ 36	$ 37	$ (1)		$ 36	$ 32	$ 4	
Earnings Per Share	$ 0.05	$ 0.05	$ (0.00)		$ 0.05	$ 0.05	$ (0.00)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) August 2014

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 1,937	$ 1,909	$ 28	Due to higher electricity volumes resulting from favorable weather earlier this year.
Gas Revenues	$ 244	208	37	Due to higher gas volumes resulting from favorable weather earlier this year.
Total Revenues	$ 2,181	2,116	65	
Cost of Sales:				
Fuel Electric Costs	681	652	(29)	Due to higher electricity volumes resulting from favorable weather earlier this year.
Gas Supply Expenses	140	104	(36)	Due to higher gas volumes resulting from favorable weather earlier this year.
Purchased Power	37	47	11	Due to lower purchases than planned.
Other Electric Cost	70	83	13	Due primarily to lower plant system consumables costs.
Total Cost of Sales	928	887	(41)	
Gross Margin:				
Electric Margin	1,149	1,127	22	Higher margins driven by favorable weather and system availability earlier this year.
Gas Margin	104	103	1	
Total Gross Margin	1,253	1,230	23	
Operating Expenses:				
O&M	476	483	7	Due to primarily to labor and benefit savings and lower material and other expenses partially offset by higher storms expenses and uncollectible accounts.
Depreciation & Amortization	227	229	2	
Taxes, Other than Income	34	34	0	
Total Operating Expenses	737	746	9	
Other income	(5)	(5)	0	
EBIT	511	478	33	
Interest Expense	111	115	3	
Income from Ongoing Operations before income taxes	400	364	36	
Income Tax Expense	151	137	(14)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**$ 249**	**$ 227**	**$ 22**	
Non Operating Income	0	-	0	
Discontinued Operations	(0)	0	(1)	
Net Income (loss)	$ 249	$ 227	$ 22	
KY Regulated Financing Costs	(21)	(21)	(0)	
KY Regulated Net Income	$ 228	$ 206	$ 22	
Earnings Per Share	$ 0.34	$ 0.31	$ 0.03	

Note: Schedules may not sum due to rounding.

Income Statement: Forecast vs. Prior Forecast & Budget

August 2014

($ Millions)

	Full Year				Full Year			
	Q2 Forecast	Q1 Forecast	Variance	Comments	Q2 Forecast	Budget	Variance	Comments
Revenues:								
Electric Revenues	$ 2,873	$ 2,877	$ (4)		$ 2,873	$ 2,815	$ 58	Due to higher electricity volumes resulting from favorable weather.
Gas Revenues	355	351	4		355	318	36	Due to higher gas volumes resulting from colder than normal weather.
Total Revenues	3,228	3,227	0		3,228	3,134	94	
Cost of Sales:								
Fuel Electric Costs	1,011	996	(15)	Due to higher electricity volumes resulting from favorable weather.	1,011	953	(58)	Due to higher electricity volumes resulting from favorable weather.
Gas Supply Expenses	197	193	(4)	Due to higher electricity volumes resulting from favorable weather.	197	162	(36)	Due to higher gas volumes resulting from colder than normal weather.
Purchased Power	66	69	3		66	72	6	Due to lower purchases than planned.
Other Electric Cost	117	124	7	Due primarily to lower plant system consumables costs.	117	127	10	Due primarily to lower plant system consumables costs.
Total Cost of Sales	1,390	1,381	(9)		1,390	1,313	(77)	
Gross Margin:								
Electric Margin	1,680	1,689	(9)	Due to higher cost of sales (see above).	1,680	1,664	16	Due to higher revenues offset by higher cost of sales (see above).
Gas Margin	158	158	0		158	157	1	
Total Gross Margin	1,837	1,846	(9)		1,837	1,820	17	
Operating Expenses:								
O&M	733	742	9	Due primarily to lower pension and medical related expenses.	733	735	2	
Depreciation & Amortization	342	343	1		342	344	2	
Taxes, Other than Income	51	51	(0)		51	51	(0)	
Total Operating Expenses	1,126	1,135	9		1,126	1,130	3	
Other income	(7)	(6)	(0)		(7)	(7)	0	
EBIT	704	705	(0)		704	684	20	
Interest Expense	170	171	1		170	172	3	
Income from Ongoing Operations before income taxes	534	533	1		534	511	23	
Income Tax Expense	202	200	(2)		202	192	(9)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**$ 333**	**$ 333**	**$ 0**		**$ 333**	**$ 319**	**$ 13**	
Non Operating Income	0	-	0		0	-	0	
Discontinued Operations	(0)	0	(1)		(0)	0	(1)	
Net Income (loss)	$ 333	$ 334	$ (1)		$ 333	$ 320	$ 13	
KY Regulated Financing Costs	(31)	(31)	0		(31)	(31)	0	
KY Regulated Net Income	$ 302	$ 302	$ (0)		$ 302	$ 288	$ 14	
Earnings Per Share	$ 0.45	$ 0.45	$ 0.00		$ 0.45	$ 0.43	$ 0.02	

Note: Schedules may not sum due to rounding.

Electric Gross Margin August 2014

($ Millions)

	MTD						YTD					
	Actual	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**	**Actual**	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**
Base Electric Margin:						♦ **$ (12)**						● **$ 2**
Energy Volumes (a)	3,070,214	3,330,724	(260,510)	$ -	$ (9)		22,857,064	22,919,415	(62,351)	$ -	$ (1)	
Energy Prices (a)					-						1	
Customer Charges (Avg. Customers)	939,670	948,654	(8,984)		(0)		939,302	946,420	(7,118)		(0)	
Demand Charges (b)	43	46			(3)		321	318			2	
ECR:						● **$ 1**						● **$ 1**
Average Rate Base	$ 1,511	$ 1,451	$ 60	10.37%	$ 0.5		$ 1,311	$ 1,282	$ 30	10.38%	$ 1.8	
Cost of Capital	10.14%	10.37%	-0.22%	$ 1,511	$ (0.3)		10.17%	10.38%	-0.21%	$ 1,311	(1.6)	
Jurisdictional Factor	89.89%	90.16%	-0.27%	$ 1,511	$ -		87.98%	88.24%	-0.27%	$ 1,311	(0.2)	
Other					$ 0.9						0.9	
DSM:						♦ **$ (0)**						♦ **$ (2)**
Program Expense (Revenue Net of Expense)	$ 0.1	$ 0.1			$ -		$ (0.1)	$ 0.3			$ (0.4)	
Lost Sales	1.7	1.9			$ (0.2)		13.6	14.9			(1.3)	
Incentive	0.1	0.1			$ -		0.8	0.8			-	
Balancing Adjustment	-	-			$ -		(0.3)	-			(0.3)	
Net Fuel Recovery	$ 0.3	$ (0.7)				● **$ 1**	$ (4)	$ (4)				♦ **$ (0)**
Purchase Power Demand	(1.9)	(2.6)				● **$ 1**	(16.2)	(20.5)				● **$ 4**
Transmission	0.9	1.1				♦ **$ (0)**	7.7	7.4				● **$ 0**
Other	(1.0)	(2.9)				● **$ 2**	(10.6)	(17.7)				● **$ 8**
Retail Margin Variance						♦ **$ (7)**						● **$ 14**
Off-System Margin Variance						● **$ 0**						● **$ 8**
Electric Margin Variance						♦ **$ (7)**						● **$ 22**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 50	1,009,639	$ 49.10	$ 56	1,132,251	$ 49.02	♦ ($6)	♦ ($6)	● $0
Commercial	22	732,000	30.36	26	797,341	32.25	♦ ($4)	♦ ($2)	♦ ($1)
Industrial	8	892,338	9.01	9	942,671	9.00	♦ ($1)	♦ ($1)	● $0
Municipals	1	174,850	4.40	1	191,620	4.16	● $0	♦ ($0)	● $0
Other	6	261,388	21.98	5	266,842	17.15	● $1	♦ ($0)	● $1
Native Load Total	**$ 86**	**3,070,214**	**$ 28.12**	**$ 95**	**3,330,724**	**$ 28.55**	♦ **($9)**	♦ **($9)**	● **$0**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 373	7,655,284	$ 48.76	$ 373	7,631,142	$ 48.86	● $1	● $1	♦ ($1)
Commercial	165	5,334,160	30.91	174	5,392,779	32.26	♦ ($9)	♦ ($2)	♦ ($7)
Industrial	60	6,658,429	8.98	60	6,684,085	8.97	♦ ($0)	♦ ($0)	● $0
Municipals	7	1,294,063	5.09	7	1,334,160	5.17	♦ ($0)	♦ ($0)	♦ ($0)
Other	43	1,915,127	22.67	34	1,877,248	18.02	● $10	● $1	● $9
Native Load Total	**$ 648**	**22,857,064**	**$ 28.35**	**$ 648**	**22,919,415**	**$ 28.25**	● **$1**	♦ **($1)**	● **$1**

(b) Demand Analysis (net of base ECR revenue):

$mil	MTD			YTD		
	Act	Bud	Variance	Act	Bud	Variance
Commercial	15	15	(0)	110	104	6
Industrial	17	19	(1)	130	135	(4)
Municipals	5	5	(0)	35	36	(1)
Other	6	6	(1)	46	44	1
Native Load Total	**43**	**46**	**(3)**	**321**	**318**	**2**

Gas Gross Margin August 2014

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	$ 5	$ 5		● $ -	$ 35	$ 35		● $ 0
Gas Supply Costs								
Gas Supply Costs	(4)	(3)	$ (1)		(135)	(99)	$ (36)	
GSC Revenue	4	3	1		133	99	34	
Net Gas Supply Costs				◆ $ (0)				◆ $ (1)
Retail Gas (a)	3	3		● $ 0	62	54		● $ 8
Wholesale Gas (a)	-	-		● $ -	-	-		● $ -
DSM	(0)	0		◆ $ (0)	0	0		◆ $ (0)
GLT	1	1		● $ 0	4	5		◆ $ (1)
WNA	-	-		● $ -	(6)	-		◆ $ (6)
Other Margin	0	0		● $ 0	1	1		● $ 0
Gas Margin Variance				◆ $ (0)				● $ 1

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 1	390,664	$ 2.64	$ 1	385,884	$ 2.64	● $0	● $ -	● $ -
Commercial	1	270,621	1.93	1	259,610	2.07	● $0	● $ -	● $ -
Industrial	0	101,509	1.51	0	53,324	1.79	● $0	● $ 0	● $ -
Public Authority	0	28,853	1.83	0	45,025	1.97	● $0	● $ -	● $ -
Transportation	1	838,966	0.96	0.70	841,731	0.87	● $0	● $ -	● $ 0
Ultimate Consumer	$ 3	1,630,613	$ 1.57	$ 3	1,585,575	$ 1.56	● $0	● $ 0	● $ -

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 38	14,373,829	$ 2.64	$ 33	12,590,075	$ 2.64	● $5	● $ 5	● $ -
Commercial	14	6,613,692	2.04	12	5,603,935	2.08	● $2	● $ 2	◆ $ (0)
Industrial	1	829,262	1.75	1	600,223	1.78	● $0	● $ 0	● $ -
Public Authority	2	1,036,641	1.97	2	960,884	2.01	● $0	● $ 0	● $ -
Transportation	7	8,401,987	0.81	6	7,655,028	0.79	● $1	● $ 1	● $ 0
Ultimate Consumer	$ 62	31,255,411	$ 1.98	$ 54	27,410,145	$ 1.97	● $8	● $ 8	◆ $ (0)

O&M August 2014

($ Millions)

	MTD								
	Actual	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 16	$ 17	$ 1	$ 0	$ (0)	$ 0	$ 1		$ (0)
Project Engineering	0	0	0	0		0	(0)		0
Transmission	2	2	1	(0)		0	0		0
Energy Supply and Analysis	1	1	0	(0)		0	0		0
Electric Distribution	7	6	(0)	(0)		(0)	0	(0)	0
Gas Distribution	2	3	0	0		0	0	(0)	(0)
Safety and Security	0	0	(0)	(0)		(0)	0	0	(0)
Customer Services	8	7	(1)	0		(0)	0	(1)	(0)
Chief Operations Officer	**36**	**37**	**1**	**(0)**	**(0)**	**1**	**1**	**(1)**	**(0)**
Information Technology	4	5	0	1		(0)	0		0
General Counsel	3	3	(0)	(0)		0	0		(0)
Human Resources	1	1	0	0		(0)	0		0
Supply Chain	0	0	0	(0)		0	(0)		0
Chief Administrative Officer	**8**	**8**	**0**	**0**		**(0)**	**0**		**0**
Chief Financial Officer	**2**	**2**	**(0)**	**(0)**		**0**	**0**		**0**
Corporate	**8**	**12**	**4**	**3**		**0**	**0**		**(0)**
O&M Total MTD	**$ 54**	**$ 59**	**$ 5**	**$ 4**	**$ (0)**	**$ 1**	**$ 1**	**$ (1)**	**$ (0)**

	YTD								
	Actual	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 155	$ 156	$ 1	$ 1	$ (0)	$ (2)	$ 2		$ (0)
Project Engineering	1	1	0	0		0	(0)		0
Transmission	19	20	1	(0)		(0)	1		0
Energy Supply and Analysis	6	6	1	0		0	0		0
Electric Distribution	56	49	(6)	(1)		(5)	0	(0)	(0)
Gas Distribution	21	21	1	(0)		1	0	(0)	(0)
Safety and Security	2	0	(2)	(1)		(0)	0	0	(0)
Customer Services	56	52	(3)	0		(1)	0	(2)	(0)
Chief Operations Officer	**315**	**306**	**(9)**	**(1)**	**(0)**	**(7)**	**3**	**(2)**	**(1)**
Information Technology	34	37	3	3		0	(0)		(0)
General Counsel	21	20	(1)	0		(1)	0		(0)
Human Resources	5	5	1	0		0	0		0
Supply Chain	2	2	0	0		(0)	(0)		0
Chief Administrative Officer	**63**	**65**	**2**	**3**		**(0)**	**(0)**		**(0)**
Chief Financial Officer	**12**	**13**	**0**	**0**		**0**	**0**		**0**
Corporate	**86**	**100**	**14**	**13**		**3**	**1**	**(0)**	**(3)**
O&M Total YTD	**$ 476**	**$ 483**	**$ 7**	**$ 15**	**$ (0)**	**$ (5)**	**$ 4**	**$ (3)**	**$ (5)**

	Full Year								
	Forecast	Budget	Total Variance	Labor	Outages	Outside Services	Materials	Uncollectible Accounts	Other
Generation	$ 244	$ 245	$ 1	$ 3	$ 1	$ (4)	$ 1		$ (1)
Project Engineering	1	1	0	(0)		(0)	(0)		0
Transmission	29	29	(1)	(0)		0	(1)		0
Energy Supply and Analysis	9	9	0	0		0	0		0
Electric Distribution	77	72	(5)	0		(4)	0	0	(1)
Gas Distribution	32	32	(0)	(0)		0	0	0	(0)
Safety and Security	3	0	(3)	(3)		(0)	0	0	(0)
Customer Services	87	79	(8)	(0)		(3)	0	(5)	(1)
Chief Operations Officer	**483**	**468**	**(16)**	**0**	**1**	**(10)**	**1**	**(5)**	**(3)**
Information Technology	55	55	0	1		(0)	(0)		(0)
General Counsel	32	32	0	(0)		0	0		(0)
Human Resources	8	8	0	0		0	0		0
Supply Chain	4	4	(0)	(0)		0	0		0
Chief Administrative Officer	**98**	**98**	**1**	**1**		**(0)**	**(0)**		**(0)**
Chief Financial Officer	**19**	**19**	**0**	**0**		**0**	**0**		**(0)**
Corporate	**133**	**150**	**17**	**19**		**1**	**(0)**	**(0)**	**(3)**
O&M Total Full Year	**$ 733**	**$ 735**	**$ 2**	**$ 20**	**$ 1**	**$ (9)**	**$ 1**	**$ (5)**	**$ (5)**

Note: Schedules may not sum due to rounding.

Financing Activities August 2014

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB									
Beg Bal	$ 924.0	$ 924.6	$ 0.6	$ 924.0	$ 924.0	$ 0.0	$ 924.0	$ 924.0	$ -
End Bal	(1.1)	924.7	925.8	(1.1)	924.7	925.8	925.8	924.9	(0.8)
Ave Bal	**$ 461.4**	**$ 924.6**	**$ 463.2**	**$ 461.4**	**$ 924.4**	**$ 463.0**	**$ 924.5**	**$ 924.6**	**$ 0.1**
Interest Exp	**$ 0.8**	**$ 0.9**	**$ 0.2**	**$ 6.1**	**$ 7.6**	**$ 1.4**	**$ 10.3**	**$ 11.3**	**$ 1.1**
Rate	**1.93%**	**1.19%**	**-0.74%**	**1.96%**	**1.21%**	**-0.75%**	**1.11%**	**1.23%**	**0.12%**
FMB/Sr Nts									
Beg Bal	$ 3,641.9	$ 3,641.8	$ (0.1)	$ 3,640.9	$ 3,640.9	$ -	$ 3,640.9	$ 3,640.9	$ -
End Bal	4,567.2	3,642.0	(925.2)	4,567.2	3,642.0	(925.2)	3,642.6	3,642.5	(0.1)
Ave Bal	**$ 4,104.5**	**$ 3,641.9**	**$ (462.6)**	**$ 4,104.0**	**$ 3,641.5**	**$ (462.5)**	**$ 3,641.8**	**$ 3,641.8**	**$ (0.0)**
Interest Exp	**$ 11.5**	**$ 11.6**	**$ 0.1**	**$ 91.9**	**$ 93.1**	**$ 1.2**	**$ 140.5**	**$ 141.4**	**$ 0.8**
Rate	**3.25%**	**3.71%**	**0.46%**	**3.32%**	**3.79%**	**0.47%**	**3.86%**	**3.88%**	**0.02%**
Short-term Debt									
Beg Bal	$ 316.0	$ 369.5	$ 53.5	$ 245.0	$ 245.0	$ -	$ 245.0	$ 245.0	$ -
End Bal	310.0	371.7	61.7	310.0	371.7	61.7	570.9	527.8	(43.1)
Ave Bal	**$ 313.0**	**$ 370.6**	**$ 57.6**	**$ 277.5**	**$ 300.9**	**$ 23.4**	**$ 357.6**	**$ 356.8**	**$ (0.8)**
Interest Exp	**$ 0.2**	**$ 0.3**	**$ 0.1**	**$ 1.4**	**$ 2.2**	**$ 0.8**	**$ 3.1**	**$ 3.6**	**$ 0.5**
Rate	**0.68%**	**0.94%**	**0.26%**	**0.74%**	**1.07%**	**0.33%**	**0.87%**	**1.00%**	**0.14%**
Total End Bal	**$ 4,876.0**	**$ 4,938.4**	**$ 62.4**	**$ 4,876.0**	**$ 4,938.4**	**$ 62.4**	**$ 5,139.3**	**$ 5,095.3**	**$ (44.0)**
Total Average Bal	**$ 4,878.9**	**$ 4,937.1**	**$ 58.2**	**$ 4,842.9**	**$ 4,866.8**	**$ 23.9**	**$ 4,923.9**	**$ 4,923.2**	**$ (0.7)**
Total Expense Excl I/C (1)	**$ 14.0**	**$ 14.4**	**$ 0.4**	**$ 111.3**	**$ 114.7**	**$ 3.4**	**$ 169.7**	**$ 172.4**	**$ 2.7**
Rate	**3.33%**	**3.38%**	**0.05%**	**3.41%**	**3.49%**	**0.09%**	**3.45%**	**3.50%**	**0.05%**

(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**	**Letters of Credit Issued**	**Unused Capacity**
LKE	$ 300	$ 75		$ 225
LG&E	500	105		395
KU	598	130	$ 198	270
TOTAL	$ 1,398	$ 310	$ 198	$ 890

Credit Metrics ($ Millions)	**YTD Actual**	**YTD +/- Bud**	**Full Year Forecast**	**Full Year +/- Bud**
FFO to Debt - LG&E	26.9%	+0.02	20.9%	-0.02
FFO to Debt - KU	27.8%	+0.04	22.4%	-0.02
Debt to EBITDA - LG&E (2)	3.11	-0.55	3.57	-0.09
Debt to EBITDA - KU (2)	3.50	-0.22	3.65	-0.07
Debt to Capitalization - LG&E (3)	46.8%	+0.00	47.0%	+0.00
Debt to Capitalization - KU (3)	46.6%	-0.01	47.0%	+0.00

(2) Actuals represent a trailing 12 months

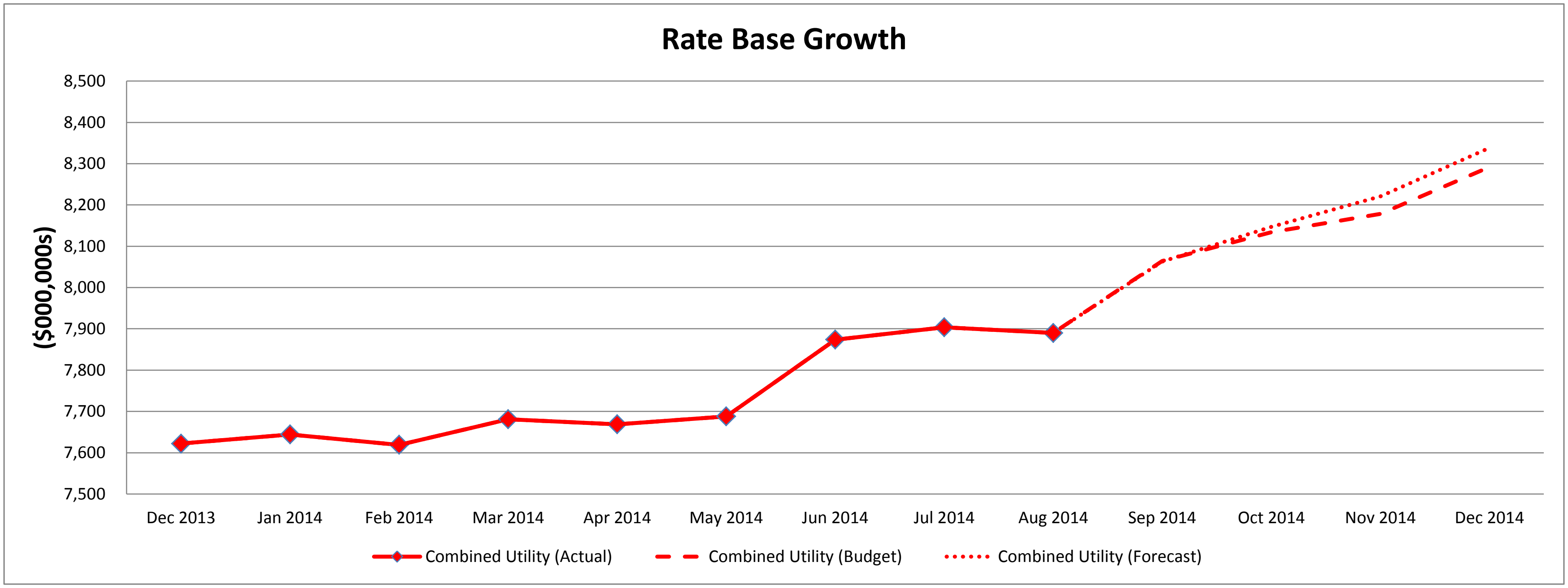
(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet August 2014

($ Millions)

	8/31/2014	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 49	$ 9	$ 40	Due to tightened Commercial Paper supply given the holiday weekend, KU and LGE accessed liquidity a day earlier than needed and carried $20m and $15m over month end, respectively.
Accounts Receivable (Trade)	381	424	(43)	Lower customer accounts receivable ($25m) and lower unbilled utility revenue ($17m).
Inventory	253	251	2	
Deferred Income Taxes	106	159	(53)	Deferred Income Taxes reclassified from asset to liability Deferred Tax Liabilities.
Prepayments and other current assets	50	113	(63)	Lower notes receivable from affiliate ($65m).
Total Current Assets	839	956	(117)	
Property, Plant, and Equipment	10,112	10,127	(16)	Lower CWIP ($65m) partially offset by higher completed construction $25m accumulated depreciation $22m.
Intangible Assets	189	190	(0)	
Other Property and Investments	1	1	(0)	
Regulatory Assets	502	488	14	Increases in GSC $15m, ARO $14m, and long term interest rate swap $9m LGE partially offset by decreases in FAC ($14m), DSM ($8m), and ECR ($5m)
Goodwill	997	997	0	
Other Long-term Assets	100	93	7	
Total Assets	**$ 12,740**	**$ 12,852**	**$ (112)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 409	$ 345	$ 64	Increases in project engineering $39m, increase in and timing of coal receipts $16m, and $9m due to timing of payables.
Accounts Payable - Affiliated Company	106	0	106	Dividend payable $106m issued to PPL based on Q2 2014 net income.
Customer Deposits	51	50	1	
Derivative Liability	5	4	1	
Accrued Taxes	76	99	(23)	Lower pre-tax income.
Other Current Liabilities	148	150	(3)	
Total Current Liabilities	794	648	146	
Debt - Affiliated Company	-	-	-	
Debt (1)	4,876	4,938	(62)	Lower issuance of Commercial Paper ($62m) due to lower pension and CapEx payments.
Total Debt	4,876	4,938	(62)	
Deferred Tax Liabilities	1,055	1,117	(62)	Deferred Tax Liabilities reclassified from liability to asset as Deferred Income Taxes.
Investment Tax Credit	132	132	(0)	
Accum Provision for Pension & Related Benefits	116	122	(6)	
Asset Retirement Obligation	276	249	27	KU Green River Ash and Environmental Pond Revaluation $27m.
Regulatory Liabilities	1,007	1,019	(12)	Decrease in long term interest rate swaps.
Derivative Liability	51	32	19	Increase due to loss on long term interest rate swaps.
Other Liabilities	245	235	10	Accrued retiree medical post employee benefits $7m which are not budgeted for in the Other Liabilities account. In December the balance is moved to the liability account where it is budgeted for.
Total Deferred Credits and Other Liabilities	2,882	2,906	(24)	
Equity	4,188	4,360	(171)	
Total Liabilities and Equity	**$ 12,740**	**$ 12,852**	**$ (112)**	

(1) Includes all ST and LT debt. See Financing Activities page for details.
Note: Schedules may not sum due to rounding.


Rate Base Growth
($000,000s)
8,500
8,400
8,300
8,200
8,100
8,000
7,900
7,800
7,700
7,600
7,500
Dec 2013
Jan 2014
Feb 2014
Mar 2014
Apr 2014
May 2014
Jun 2014
Jul 2014
Aug 2014
Sep 2014
Oct 2014
Nov 2014
Dec 2014
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Forecast)

Performance Report

September 2014

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Kentucky Regulated Dashboard

September 2014

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	1.54	0.39	1.27	1.30	1.27	1.29
Employee lost-time incidents	0	0	5	1	5	3
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,835	2,866	26,630	26,650	34,787	34,780
Utility EFOR	6.2%	5.9%	5.0%	5.9%	N/A	5.9%
Utility EAF	87.4%	90.3%	82.8%	83.7%	N/A	82.5%
Steam Fleet Commercial Availability	93.8%	91.5%	93.9%	91.5%	N/A	91.5%
Combined SAIFI	0.08	0.10	0.78	0.98	N/A	1.20
Combined SAIDI (minutes)	6.16	8.72	73.80	89.62	N/A	107.60
GwH Sales						
Residential	727	901	8,382	8,533	10,848	10,962
Commercial	659	669	5,994	6,061	7,877	7,952
Industrial	832	795	7,490	7,479	9,957	10,011
Municipals	149	171	1,442	1,506	1,873	1,969
Other	251	227	2,166	2,104	2,833	2,788
Off-System Sales	45	34	409	251	465	273
Total	2,662	2,798	25,884	25,934	33,854	33,954
Weather-Normalized Sales Growth			**TTM**			
Residential			-0.83%			
Commercial			-0.43%			
Industrial			2.90%			
Municipal			-0.56%			
Other			1.25%			
Total			0.55%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[1]	7.5%	8.0%	9.8%	9.2%	9.1%	8.7%
Electric Margins	$132	$143	$1,281	$1,269	$1,676	$1,664
Gas Margins	$8	8	112	112	158	157
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$17	$9	$90	$106	$121	$126
ECR	$73	$48	$523	$461	$729	$603
Generation	$14	$13	$58	$76	$113	$121
Transmission	$6	$8	$61	$56	$85	$77
Electric Distribution	$15	$13	$102	$107	$146	$143
Gas Distribution	$7	$8	$54	$62	$77	$80
Customer Services	$1	$2	$13	$16	$19	$20
IT and Other	$4	$4	$24	$38	$38	$50
Total	$139	$104	$925	$921	$1,329	$1,221
O&M ($ millions)[2]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$38	$42	$352	$348	$482	$468
Administrative	8	9	$71	74	97	98
Finance	2	2	$14	14	19	19
Burdens & Other Charges	10	12	$96	112	133	150
Total	$58	$65	$534	$549	$731	$735
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,452	3,562	3,452	3,562	3,527	3,549
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	2	9	9	N/A	14
NERC Possible Violations[3]	0	0	5	9	N/A	11

Variance Explanations

- Current month capital was $34 million higher than budget due primarily to increased costs on environmental air projects at Mill Creek, timing of spend on environmental air projects at Trimble County and Ghent and timing of spend on Cane Run Unit 7.

- Full year higher capital due primarily to increased costs related to Ghent environmental air projects (Units 3 and 4 economizer work) and Mill Creek environmental air projects (Units 1, 2 and 4 fabric filters and wet flue gas desulfurization units) with some non-environmental spend offsets due to cost reductions.

- Current month lower margins driven by mild weather resulting in $11 million lower retail electric energy and demand charge revenues.

- YTD higher margins due to $8 million from the sale of excess generation driven by favorable plant availability and higher market prices during Q1, $7 million from lower cost of production margin expenses, and $5 million from lower purchase power demand costs partially offset by $9 million lower retail electric energy and demand revenues.

- Current month lower O&M primarily due to $4 million of labor and benefit savings, $4 million savings due to maintenance and outage timing shifts, and $1 million of materials expense savings, partially offset by $2 million higher uncollectible accounts.

- YTD lower O&M primarily due to $20 million of labor and benefit savings and $3 million lower material and other expenses partially offset by $7 million of higher storms expenses and $4 million higher uncollectible accounts.

Major Developments

- LKE reached two more construction milestones as Mill Creek Unit 4 recently began its twelve-week tie-in outage for the new FGD and baghouse; and the 8.2 mile 20” natural gas pipeline constructed to serve Cane Run 7 was charged to full pressure and placed into service.

- LKE and interveners (including Sierra Club and Kentucky Industrial Utility Customers) submitted a Joint Motion for Consideration and Approval of an Agreement, Stipulation, and Recommendation supporting the issuance of a CPCN for the construction of the 10 MW Solar Facility at the Brown Generating Station. The KPSC also issued an Order scheduling a hearing for November 24, 2014.

- LKE and all parties in the DSM/EE proceeding filed Post-Hearing Briefs. This proceeding included plans to expand and enhance five DSM programs for 2015 -2018, and offer up to 10,000 customers a smart meter on a voluntary basis. LKE requested an Order by mid-November.

Significant Future Events

- Rate case preparations are underway in anticipation of a November filing with the KPSC.

- Heavy construction is proceeding at Mill Creek, Ghent, Brown, Cane Run and Trimble County. All projects are expected to be in service by target completion dates. The Ghent Unit 4 tie-in outage for its new baghouse will begin in October and is scheduled to be finished by the end of the year.

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[1] Excludes goodwill and other purchase accounting adjustments.

[2] Net of cost recovery mechanisms.

[3] The possible violation issues for YTD Actual are believed to be minimal risk and are expected to receive a zero dollar penalty from the regulator.

Income Statement: Actual vs. Budget and Forecast (Month) September 2014

($ Millions)

	MTD				MTD			
	Actual	**Budget**	**Variance**	**Comments**	**Actual**	**Q2 Forecast**	**Variance**	**Comments**
Revenues:								
Electric Revenues	$ 218	$ 236	$ (18)	Due to lower electricity volumes resulting from unfavorable weather.	$ 218	$ 233	$ (15)	Due to lower electricity volumes resulting from unfavorable weather.
Gas Revenues	14	12	1		14	13	1	
Total Revenues	232	249	(16)		232	246	(13)	
Cost of Sales:								
Fuel Electric Costs	72	76	4	Due to lower electricity volumes resulting from unfavorable weather.	72	77	5	Due to lower electricity volumes resulting from unfavorable weather.
Gas Supply Expenses	5	4	(1)		5	4	(1)	
Purchased Power	4	5	1		4	5	1	
Other Electric Cost	10	11	1		10	12	2	
Total Cost of Sales	91	97	6	Due to lower electricity volumes resulting from unfavorable weather.	91	99	8	Due to lower electricity volumes resulting from unfavorable weather.
Gross Margin:								
Electric Margin	132	143	(11)	Due to mild weather resulting in lower retail electric energy and demand charge revenues.	132	138	(6)	Due to mild weather resulting in lower retail electric energy and demand charge revenues.
Gas Margin	8	8	(0)		8	8	(0)	
Total Gross Margin	140	151	(11)		140	147	(6)	
Operating Expenses:								
O&M	58	65	7	Due primarily to labor and benefit savings.	58	66	8	Due primarily to labor and benefit savings.
Depreciation & Amortization	29	29	(0)		29	29	(0)	
Taxes, Other than Income	4	4	(0)		4	4	0	
Total Operating Expenses	91	98	7		91	99	8	
Other income (expense)	(0)	(0)	(0)		(0)	(0)	(0)	
EBIT	50	53	(4)		50	47	2	
Interest Expense	14	14	0		14	14	0	
Income from Ongoing Operations before income taxes	36	39	(3)		36	33	3	
Income Tax Expense	14	15	0		14	12	(2)	
Net Income (loss) from ongoing operations	**22**	**25**	**$ (3)**		**$ 22**	**21**	**$ 1**	
Non Operating Income	0	0	0		0	0	0	
Discontinued Operations	0	0	0		0	0	0	
Net Income (loss)	$ 21	$ 24	$ (3)		$ 21	$ 21	$ 1	
KY Regulated Financing Costs	(3)	(3)	0		(3)	(3)	0	
KY Regulated Net Income	$ 19	$ 22	$ (3)		$ 19	$ 18	$ 1	
Earnings Per Share	$ 0.03	$ 0.03	$ (0.00)		$ 0.03	$ 0.03	$ (0.00)	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD) September 2014

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,155	$ 2,145	$ 10	Due to higher electricity volumes resulting from favorable weather earlier this year.
Gas Revenues	$ 258	220	38	Due to higher gas volumes resulting from favorable weather earlier this year.
Total Revenues	$ 2,413	2,365	48	
Cost of Sales:				
Fuel Electric Costs	753	728	(25)	Due to higher electricity volumes resulting from favorable weather earlier this year.
Gas Supply Expenses	145	109	(37)	Due to higher gas volumes resulting from favorable weather earlier this year.
Purchased Power	41	53	11	Due to lower purchases than planned.
Other Electric Cost	80	94	14	Due primarily to lower plant system consumables costs.
Total Cost of Sales	1,019	983	(36)	
Gross Margin:				
Electric Margin	1,281	1,269	12	Due to the sale of excess generation driven by favorable plant availability and higher market prices during Q1, lower cost of production margin expenses, and lower purchase power demand costs partially offset by lower retail electric energy and demand revenues.
Gas Margin	112	112	0	
Total Gross Margin	1,393	1,381	12	
Operating Expenses:				
O&M	534	549	15	Due to primarily to labor and benefit savings and lower material and other expenses partially offset by higher storms expenses and uncollectible accounts.
Depreciation & Amortization	256	257	2	
Taxes, Other than Income	38	38	0	
Total Operating Expenses	827	844	17	
Other income (expense)	(6)	(6)	(0)	
EBIT	560	532	28	
Interest Expense	125	129	4	
Income from Ongoing Operations before income taxes	435	403	32	
Income Tax Expense	165	152	(14)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**$ 270**	**$ 251**	**$ 19**	
Non Operating Income	0	-	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 271	$ 251	$ 20	
KY Regulated Financing Costs	(23)	(23)	0	
KY Regulated Net Income	$ 247	$ 228	$ 19	
Earnings Per Share	$ 0.37	$ 0.34	$ 0.03	

Note: Schedules may not sum due to rounding.

Income Statement: Forecast vs. Prior Forecast & Budget

September 2014

($ Millions)

	Full Year				Full Year			
	Q3 Forecast	Q2 Forecast	Variance	Comments	Q3 Forecast	Budget	Variance	Comments
Revenues:								
Electric Revenues	$ 2,817	$ 2,873	$ (55)	Due to lower electricity volumes resulting from unfavorable weather.	$ 2,817	$ 2,815	$ 2	
Gas Revenues	357	355	2		357	318	39	Due to higher gas volumes resulting from colder than normal weather.
Total Revenues	3,175	3,228	(53)		3,175	3,134	41	
Cost of Sales:								
Fuel Electric Costs	976	1,011	35	Due to lower electricity volumes resulting from unfavorable weather.	976	953	(23)	Due to higher electricity volumes resulting from favorable weather.
Gas Supply Expenses	199	197	(2)		199	162	(38)	Due to higher gas volumes resulting from colder than normal weather.
Purchased Power	55	66	10	Due to lower purchases than planned.	55	72	16	Due to lower purchases than planned.
Other Electric Cost	110	117	7	Due primarily to lower plant system consumables costs.	110	127	17	Due primarily to lower plant system consumables costs.
Total Cost of Sales	1,341	1,390	50		1,341	1,313	(27)	
Gross Margin:								
Electric Margin	1,676	1,680	(4)		1,676	1,664	12	Due to higher revenues offset by higher cost of sales (see above).
Gas Margin	158	158	0		158	157	1	
Total Gross Margin	1,834	1,837	(3)		1,834	1,821	13	
Operating Expenses:								
O&M	731	733	3		731	735	4	
Depreciation & Amortization	343	342	(1)		343	344	0	
Taxes, Other than Income	51	51	0		51	51	(0)	
Total Operating Expenses	1,125	1,126	1		1,125	1,130	5	
Other income (expense)	(6)	(7)	0		(6)	(7)	0	
EBIT	703	704	(1)		703	684	19	
Interest Expense	168	170	2		168	172	5	Favorable interest rates.
Income from Ongoing Operations before income taxes	535	534	1		535	511	24	
Income Tax Expense	202	202	(1)		202	192	(10)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**333**	**$ 333**	**$ 0**		**$ 333**	**$ 319**	**$ 14**	
Non Operating Income	0	0	(0)		0	-	0	
Discontinued Operations	(0)	0	(0)		(0)	0	(0)	
Net Income (loss)	$ 333	$ 333	$ 0		$ 333	$ 320	$ 14	
KY Regulated Financing Costs	(31)	(31)	-		(31)	(31)	0	
KY Regulated Net Income	$ 302	$ 302	$ 0		$ 302	$ 288	$ 14	
Earnings Per Share	$ 0.45	$ 0.45	$ (0.00)		$ 0.45	$ 0.43	$ 0.02	

Note: Schedules may not sum due to rounding.

Electric Gross Margin

September 2014

($ Millions)

	MTD						YTD					
	Actual	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**	**Actual**	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**
Base Electric Margin:						◆ **$ (11)**						◆ **$ (9)**
Energy Volumes (a)	2,617,449	2,763,701	(146,251)	$ -	$ (8)		25,474,513	25,683,116	(208,603)	$ -	$ (9)	
Energy Prices (a)					0						1	
Customer Charges (Avg. Customers)	940,312	948,669	(8,357)		(0)		939,415	946,670	(7,255)		(0)	
Demand Charges (b)	41	45			(3)		362	363			(1)	
ECR:						● **$ 1**						● **$ 2**
Average Rate Base	$ 1,567	$ 1,452	$ 116	10.46%	$ 0.9		$ 1,340	$ 1,301	$ 39	10.39%	$ 2.7	
Cost of Capital	10.14%	10.46%	-0.32%	$ 1,567	$ (0.4)		10.17%	10.39%	-0.22%	$ 1,340	(2.0)	
Jurisdictional Factor	91.09%	89.26%	1.83%	$ 1,567	$ 0.2		88.38%	88.37%	0.01%	$ 1,340	-	
Other					$ -						1.0	
DSM:						◆ **$ (0)**						◆ **$ (2)**
Program Expense (Revenue Net of Expense)	$ 0.1	$ 0.1			$ -		$ -	$ 0.4			$ (0.4)	
Lost Sales	1.6	1.9			$ (0.3)		15.2	16.7			(1.5)	
Incentive	0.1	0.1			$ -		0.9	0.9			-	
Balancing Adjustment	-	-			$ -		(0.3)	-			(0.3)	
Net Fuel Recovery	$ (0.8)	$ (0.4)				◆ **$ (0)**	$ (5)	$ (4)				◆ **$ (0)**
Purchase Power Demand	(2.0)	(2.5)				● **$ 1**	(18.2)	(23.1)				● **$ 5**
Transmission	0.8	1.1				◆ **$ (0)**	8.5	8.5				● **$ -**
Other	(2.6)	(2.4)				◆ **$ (0)**	(13.2)	(20.0)				● **$ 9**
Retail Margin Variance						◆ **$ (11)**						● **$ 4**
Off-System Margin Variance						● **$ 0**						● **$ 8**
Electric Margin Variance						◆ **$ (11)**						● **$ 12**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 36	727,092	$ 49.19	$ 44	901,493	$ 49.06	◆ ($8)	◆ ($9)	● $0
Commercial	20	659,620	29.93	21	668,649	31.80	◆ ($2)	◆ ($0)	◆ ($1)
Industrial	8	831,421	8.99	7	795,209	9.00	● $0	● $0	● $0
Municipals	1	148,406	5.69	1	171,460	4.16	● $0	◆ ($0)	● $0
Other	5	250,910	21.63	4	226,889	17.60	● $1	● $0	● $1
Native Load Total	**$ 69**	**2,617,449**	**$ 26.46**	**$ 77**	**2,763,701**	**$ 27.99**	◆ **($8)**	◆ **($8)**	● **$0**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume (MWH)**	**Price ($/MWH)**	**Revenue $mil**	**Volume $mil**	**Price $mil**
Residential	$ 409	8,382,376	$ 48.80	$ 417	8,532,636	$ 48.88	◆ ($8)	◆ ($7)	◆ ($1)
Commercial	185	5,993,780	30.80	195	6,061,427	32.21	◆ ($11)	◆ ($2)	◆ ($8)
Industrial	67	7,489,850	8.98	67	7,479,295	8.98	● $0	● $0	● $0
Municipals	7	1,442,469	5.15	8	1,505,621	5.05	◆ ($0)	◆ ($0)	● $0
Other	49	2,166,037	22.55	38	2,104,137	17.97	● $11	● $1	● $10
Native Load Total	**$ 717**	**25,474,513**	**$ 28.16**	**$ 725**	**25,683,116**	**$ 28.22**	◆ **($8)**	◆ **($9)**	● **$1**

(b) Demand Analysis (net of base ECR revenue):

	MTD			YTD		
$mil	**Act**	**Bud**	**Variance**	**Act**	**Bud**	**Variance**
Commercial	14	15	(1)	124	119	5
Industrial	17	18	(2)	147	153	(6)
Municipals	4	5	(1)	38	40	(2)
Other	6	6	-	52	51	1
Native Load Total	**41**	**45**	**(3)**	**362**	**363**	**(1)**

Gas Gross Margin September 2014

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		**● $ -**	**$ 45**	**$ 45**		**● $ 0**
Gas Supply Costs								
Gas Supply Costs	(5)	(4)	$ (1)		(143)	(106)	$ (37)	
GSC Revenue	5	4	1		142	106	36	
Net Gas Supply Costs				**● $ 0**				**◆ $ (2)**
Retail Gas (a)	**3**	**3**		**◆ $ (0)**	**67**	**59**		**● $ 8**
Wholesale Gas (a)	**-**	**-**		**● $ -**	**-**	**-**		**● $ -**
DSM	**-**	**0**		**◆ $ (0)**	**0**	**1**		**◆ $ (0)**
GLT	**1**	**1**		**● $ 0**	**5**	**6**		**◆ $ (1)**
WNA	**-**	**-**		**● $ -**	**(6)**	**-**		**◆ $ (6)**
Other Margin	**0**	**0**		**● $ 0**	**2**	**1**		**● $ 0**
Gas Margin Variance				**● $ 0**				**● $ 0**

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 1	403,181	$ 2.64	$ 1	421,780	$ 2.64	● $0	● $ -	● $ -
Commercial	1	259,145	2.04	1	286,162	2.08	◆ ($0)	◆ $ (0)	● $ -
Industrial	0	83,248	1.65	0	58,357	1.74	● $0	● $ -	● $ -
Public Authority	0	39,105	1.80	0	33,535	1.89	● $0	● $ -	● $ -
Transportation	1	833,459	0.89	0.80	816,781	0.93	◆ ($0)	● $ -	● $ -
Ultimate Consumer	$ 3	1,618,138	$ 1.57	$ 3	1,616,616	$ 1.63	◆ ($0)	● $ -	◆ $ (0)

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 40	15,167,674	$ 2.64	$ 35	13,397,739	$ 2.64	● $5	● $ 5	● $ -
Commercial	15	7,143,458	2.04	13	6,149,707	2.08	● $2	● $ 2	◆ $ (0)
Industrial	2	1,014,019	1.71	1	711,904	1.78	● $0	● $ 1	◆ $ (0)
Public Authority	2	1,104,599	1.96	2	1,039,444	2.00	● $0	● $ 0	● $ -
Transportation	8	10,074,412	0.83	8	9,313,541	0.81	● $1	● $ 1	● $ 0
Ultimate Consumer	$ 67	34,504,162	$ 1.94	$ 59	30,612,335	$ 1.93	● $8	● $ 8	◆ $ (0)

O&M **September 2014**

($ Millions)

	MTD								
	Actual	**Budget**	**Total Variance**	**Labor**	**Outages**	**Outside Services**	**Materials**	**Uncollectible Accounts**	**Other**
Generation	$ 18	$ 23	$ 5	$ 1	$ 3	$ 2	$ 1		$ (0)
Project Engineering	0	0	0	0		0	(0)		0
Transmission	2	2	(0)	(0)		(0)	0		(0)
Energy Supply and Analysis	1	1	0	0		0	0		0
Electric Distribution	5	6	1	1		0	0	(0)	0
Gas Distribution	4	3	(1)	(0)		(1)	(0)	(0)	(0)
Safety and Security	0	0	(0)	(0)		(0)	(0)	0	(0)
Customer Services	8	7	(1)	0		0	0	(1)	(0)
Chief Operations Officer	**38**	**42**	**4**	**1**	**3**	**1**	**1**	**(1)**	**0**
Information Technology	4	5	1	1		0	(0)		0
General Counsel	4	3	(0)	0		(0)	0		(0)
Human Resources	1	1	0	0		0	0		0
Supply Chain	0	0	0	0		0	(0)		(0)
Chief Administrative Officer	**8**	**9**	**1**	**1**		**0**	**(0)**		**0**
Chief Financial Officer	**2**	**2**	**0**	**0**		**(0)**	**0**		**(0)**
Corporate	**10**	**12**	**2**	**3**		**0**	**0**	**(0)**	**(1)**
O&M Total MTD	**$ 58**	**$ 65**	**$ 7**	**$ 4**	**$ 3**	**$ 1**	**$ 1**	**$ (2)**	**$ (0)**

	YTD								
	Actual	**Budget**	**Total Variance**	**Labor**	**Outages**	**Outside Services**	**Materials**	**Uncollectible Accounts**	**Other**
Generation	$ 173	$ 179	$ 6	$ 2	$ 2	$ (1)	$ 4		$ (1)
Project Engineering	1	1	0	0		0	(0)		0
Transmission	21	22	1	(0)		(1)	1		0
Energy Supply and Analysis	6	7	1	0		0	0		0
Electric Distribution	61	55	(6)	(1)		(5)	0	(0)	(0)
Gas Distribution	24	24	(0)	(0)		0	(0)	(0)	(0)
Safety and Security	2	0	(2)	(2)		(0)	0	0	(0)
Customer Services	63	59	(4)	1		(1)	0	(4)	(0)
Chief Operations Officer	**352**	**348**	**(5)**	**(0)**	**2**	**(7)**	**5**	**(4)**	**(1)**
Information Technology	38	42	4	3		0	(0)		(0)
General Counsel	25	24	(1)	0		(1)	0		(1)
Human Resources	5	6	1	0		0	0		0
Supply Chain	3	3	0	0		(0)	(0)		0
Chief Administrative Officer	**71**	**74**	**3**	**4**		**(0)**	**(0)**		**(0)**
Chief Financial Officer	**14**	**14**	**0**	**0**		**0**	**0**		**(0)**
Corporate	**96**	**112**	**16**	**16**		**3**	**1**	**(0)**	**(4)**
O&M Total YTD	**$ 534**	**$ 549**	**$ 15**	**$ 20**	**$ 2**	**$ (4)**	**$ 7**	**$ (4)**	**$ (6)**

	Full Year								
	Forecast	**Budget**	**Total Variance**	**Labor**	**Outages**	**Outside Services**	**Materials**	**Uncollectible Accounts**	**Other**
Generation	$ 244	$ 245	$ 1	$ 4	$ (1)	$ 0	$ 1		$ (3)
Project Engineering	1	1	0	0		0	(0)		0
Transmission	29	29	(1)	(1)		1	(1)		1
Energy Supply and Analysis	9	9	1	0		0	0		0
Electric Distribution	78	72	(6)	(0)		(5)	0	0	(1)
Gas Distribution	32	32	0	(1)		1	0	(0)	0
Safety and Security	3	0	(3)	(2)		(0)	0	0	(1)
Customer Services	87	79	(8)	1		(3)	0	(5)	(1)
Chief Operations Officer	**482**	**468**	**(15)**	**0**	**(1)**	**(5)**	**0**	**(5)**	**(4)**
Information Technology	53	55	2	4		(1)	(0)		(0)
General Counsel	33	32	(1)	(0)		(1)	0		(0)
Human Resources	8	8	0	0		0	0		0
Supply Chain	4	4	(0)	(0)		0	0		0
Chief Administrative Officer	**97**	**98**	**1**	**4**		**(2)**	**(0)**		**(0)**
Chief Financial Officer	**19**	**19**	**0**	**0**		**0**	**0**		**(0)**
Corporate	**133**	**150**	**18**	**19**		**(0)**	**(0)**	**(0)**	**(1)**
O&M Total Full Year	**$ 731**	**$ 735**	**$ 4**	**$ 23**	**$ (1)**	**$ (7)**	**$ (0)**	**$ (5)**	**$ (6)**

Note: Schedules may not sum due to rounding.

Financing Activities — September 2014

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB									
Beg Bal	$ 923.9	$ 924.7	$ 0.8	$ 924.0	$ 924.0	$ 0.0	$ 924.0	$ 924.0	$ -
End Bal	923.9	924.7	0.8	923.9	924.7	0.8	924.8	924.9	0.2
Ave Bal	**$ 923.9**	**$ 924.7**	**$ 0.8**	**$ 924.0**	**$ 924.4**	**$ 0.5**	**$ 924.1**	**$ 924.6**	**$ 0.4**
Interest Exp	**$ 0.8**	**$ 0.9**	**$ 0.2**	**$ 6.9**	**$ 8.5**	**$ 1.6**	**$ 9.6**	**$ 11.3**	**$ 1.8**
Rate	**1.00%**	**1.23%**	**0.22%**	**0.98%**	**1.21%**	**0.23%**	**1.03%**	**1.23%**	**0.19%**
FMB/Sr Nts									
Beg Bal	$ 3,642.1	$ 3,642.0	$ (0.1)	$ 3,640.9	$ 3,640.9	$ -	$ 3,640.9	$ 3,640.9	$ -
End Bal	3,642.2	3,642.1	(0.1)	3,642.2	3,642.1	(0.1)	3,642.7	3,642.5	(0.1)
Ave Bal	**$ 3,642.1**	**$ 3,642.1**	**$ (0.1)**	**$ 3,641.5**	**$ 3,641.6**	**$ 0.0**	**$ 3,641.8**	**$ 3,641.8**	**$ -**
Interest Exp	**$ 11.5**	**$ 11.6**	**$ 0.1**	**$ 103.4**	**$ 104.8**	**$ 1.3**	**$ 139.7**	**$ 141.4**	**$ 1.6**
Rate	**3.79%**	**3.83%**	**0.05%**	**3.75%**	**3.79%**	**0.05%**	**3.84%**	**3.88%**	**0.04%**
Short-term Debt									
Beg Bal	$ 310.0	$ 371.7	$ 61.7	$ 245.0	$ 245.0	$ -	$ 245.0	$ 245.0	$ -
End Bal	370.5	373.6	3.2	370.5	373.6	3.2	540.4	527.8	(12.6)
Ave Bal	**$ 340.2**	**$ 372.7**	**$ 32.5**	**$ 307.7**	**$ 309.0**	**$ 1.3**	**$ 328.7**	**$ 356.8**	**$ 28.2**
Interest Exp	**$ 0.2**	**$ 0.3**	**$ 0.1**	**$ 1.6**	**$ 2.5**	**$ 0.9**	**$ 2.1**	**$ 3.6**	**$ 1.5**
Rate	**0.68%**	**0.97%**	**0.29%**	**0.68%**	**1.06%**	**0.38%**	**0.64%**	**1.00%**	**0.36%**
Total End Bal	**$ 4,936.6**	**$ 4,940.5**	**$ 3.8**	**$ 4,936.6**	**$ 4,940.5**	**$ 3.8**	**$ 5,107.9**	**$ 5,095.3**	**$ (12.6)**
Total Average Bal	**$ 4,906.3**	**$ 4,939.4**	**$ 33.1**	**$ 4,873.2**	**$ 4,875.0**	**$ 1.8**	**$ 4,894.6**	**$ 4,923.2**	**$ 28.6**
Total Expense Excl I/C (1)	**$ 13.9**	**$ 14.4**	**$ 0.4**	**$ 125.3**	**$ 129.1**	**$ 3.8**	**$ 167.5**	**$ 172.4**	**$ 4.8**
Rate	**3.41%**	**3.49%**	**0.08%**	**3.39%**	**3.49%**	**0.10%**	**3.42%**	**3.50%**	**0.08%**

(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	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 97		$ 203
LG&E	500	143		357
KU	598	130	$ 198	270
TOTAL	$ 1,398	$ 370	$ 198	$ 830

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud	Full Year Forecast	Full Year +/- Bud
FFO to Debt - LG&E	23.1%	+0.02	23.4%	+0.01
FFO to Debt - KU	25.3%	+0.04	25.0%	+0.01
Debt to EBITDA - LG&E (2)	3.20	-0.47	3.45	-0.22
Debt to EBITDA - KU (2)	3.52	-0.20	3.74	+0.02
Debt to Capitalization - LG&E (3)	46.9%	+0.01	47.0%	+0.00
Debt to Capitalization - KU (3)	46.4%	-0.00	47.0%	+0.00

(2) Actuals represent a trailing 12 months

(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

Balance Sheet September 2014

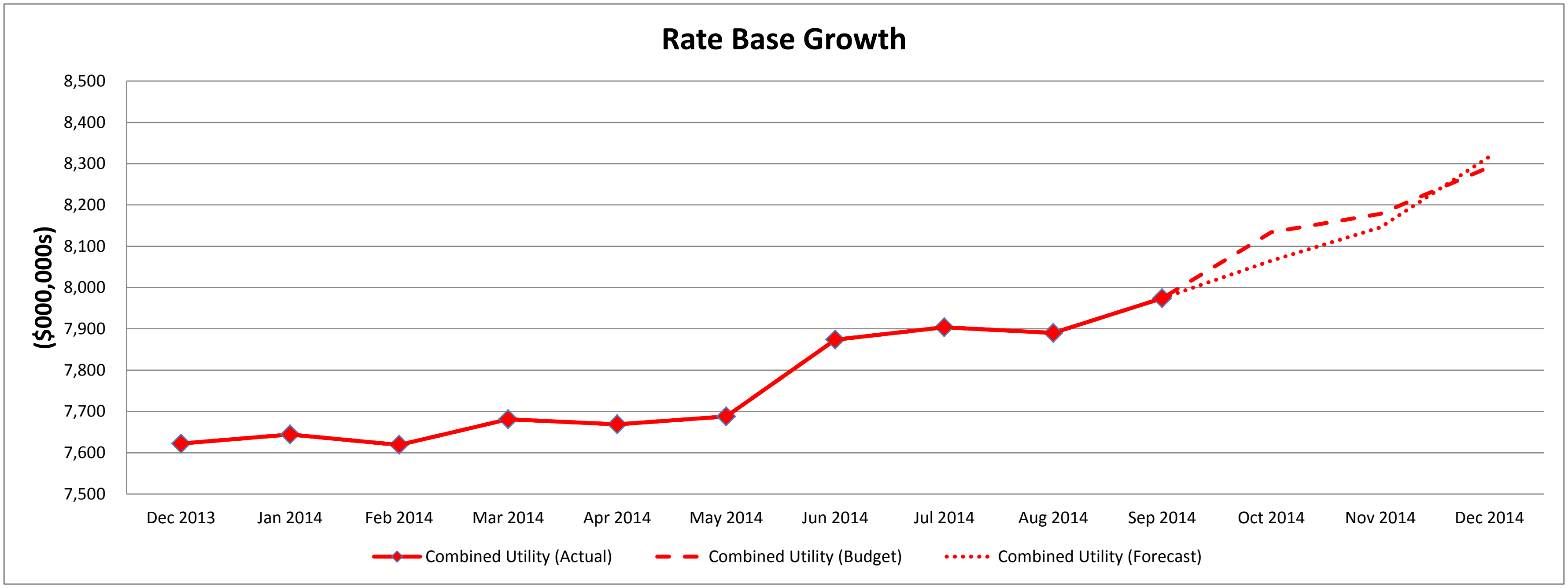
($ Millions)

	9/30/2014	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 47	$ 9	$ 38	Higher investment balances of $33m due to timing of CP due dates.
Accounts Receivable (Trade)	355	410	(55)	Lower unbilled utility revenue ($49m) and lower customer accounts receivable ($4m).
Inventory	274	262	12	Higher fuel related costs of $10m.
Deferred Income Taxes	69	159	(90)	Deferred Income Taxes reclassified from asset to liability Deferred Tax Liabilities.
Prepayments and other current assets	69	113	(44)	Lower notes receivable from affiliate ($70m) partially offset by higher intercompany income tax receivable $28m.
Total Current Assets	815	954	(139)	
Property, Plant, and Equipment	10,219	10,201	18	Higher completed construction $269m and accumulated depreciation $22m partially offset by lower CWIP ($275m).
Intangible Assets	185	186	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets	506	480	26	Increases in ARO $16m, GSC $15m, and long term interest rate swap $11m LGE partially offset by decreases in FAC ($8m), DSM ($8m), and ECR ($5m)
Goodwill	997	997	-	
Other Long-term Assets	104	93	11	Higher due to $6m increase in value of forward starting swaps and $5m from the CPCN being put on hold for GR5 and funds being moved to preliminary survey account.
Total Assets	**$ 12,827**	**$ 12,912**	**$ (85)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 430	$ 344	$ 87	Increases in project engineering $39m, increase in and timing of coal receipts $16m, and $9m due to timing of payables.
Accounts Payable - Affiliated Company	0	0	0	
Customer Deposits	51	50	1	
Derivative Liability	4	4	1	
Accrued Taxes	44	68	(25)	Lower pre-tax income.
Other Current Liabilities	171	165	6	
Total Current Liabilities	701	631	70	
Debt - Affiliated Company	22	-	22	Short term note payable made to PPL.
Debt (1)	4,914	4,940	(26)	Lower issuance of Commercial Paper ($26m) due to lower pension and CapEx payments.
Total Debt	4,937	4,940	(4)	
Deferred Tax Liabilities	1,131	1,193	(62)	Deferred Tax Liabilities reclassified from liability to asset as Deferred Income Taxes.
Investment Tax Credit	132	132	(0)	
Accum Provision for Pension & Related Benefits	116	122	(6)	
Asset Retirement Obligation	275	250	26	KU Green River Ash and Environmental Pond Revaluation $27m.
Regulatory Liabilities	1,021	1,015	6	
Derivative Liability	43	32	11	Increase due to loss on long term interest rate swaps.
Other Liabilities	243	233	11	Accrued retiree medical post employee benefits $8m which are not budgeted for in the Other Liabilities account. In December the balance is moved to the liability account where it is budgeted for.
Total Deferred Credits and Other Liabilities	2,960	2,976	(16)	
Equity	4,230	4,364	(135)	
Total Liabilities and Equity	**$ 12,827**	**$ 12,912**	**$ (85)**	

(1) Includes all ST and LT debt. See Financing Activities page for details.

Note: Schedules may not sum due to rounding.

YTD	Actual	Budget	Variance	Comments
Net Income	270	251	19	Mostly due to higher electric and gas volumes resulting from favorable weather earlier in the year. See income statement for more details.
Depreciation	279	271	8	
Deferred Income Taxes	251	224	27	Differences in how annual estimates are spread in actuals vs. budget.
Other Balance Sheet Movements	(92)	51	(142)	See balance sheet.
Funds From Operations	**709**	**797**	**(88)**	
Changes in accounts receivables	54	(0)	55	Lower unbilled utility revenue offset by higher customer accounts receivable.
Changes in inventories	4	14	(10)	Higher fuel related costs.
Change in Accounts Payable	81	(9)	90	Increases in project engineering, in and timing of coal receipts, and due to timing of payables.
Change in Working Capital	**140**	**5**	**135**	
Operating Cash flow	**848**	**801**	**47**	
Capex	(843)	(921)	77	Lower due to milestone shifts on Ghent environmental air projects partially offset by higher than budgeted spending on Mill Creek environmental air projects and timing of spend on Cane Run Unit 7.
Other Investing	73	0	73	LKE cash from tax settlements with PPL.
Loans to Affiliates	0	0	0	
Investing Cash flow	**(770)**	**(921)**	**151**	
Dividends	(327)	(238)	(89)	Higher due to liquidity of LKE cash related to PPL tax settlements.
Equity Infusion	139	202	(63)	Budgeted KU and LGE capital distribution but only made distribution to KU in March and to LGE in September.
Net Borrowings	122	129	(8)	
Other	0	0	0	
Financing Cash flow	**(66)**	**93**	**(160)**	
Net increase (decrease) in cash	**12**	**(26)**	**38**	


Rate Base Growth
($000,000s)
8,500
8,400
8,300
8,200
8,100
8,000
7,900
7,800
7,700
7,600
7,500
Dec 2013
Jan 2014
Feb 2014
Mar 2014
Apr 2014
May 2014
Jun 2014
Jul 2014
Aug 2014
Sep 2014
Oct 2014
Nov 2014
Dec 2014
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Forecast)

Combined KU and LG&E ROE (TTM) Sept 2014

KU and LG&E Combined

Reconciliation of Allowed Return to

9/30/14 Trailing Twelve Months Regulatory Return and

Book ROE from Ongoing Operations

Allowed Return [1]		10.32%	
Adjustments (net of tax):			
Change in capitalization - non ECR	-1.46%		Growth in non-ECR capitalization (rate base) between rate cases does not earn a return
Change in ROE from average mechanism rate base gr	0.00%		Mechanisms have a real-time return
Change in weighted cost of debt	-0.25%		Additional borrowings offset by favorable rates
Change in margins	2.20%		Primarily new rates since last rate cases
Change in allowed expenses	-0.97%		Inflationary increases
		-0.48%	
Actual Regulated ROE		9.84%	
Adjustments (net of tax):			
Impact of non-recoverable purchase accounting	-1.82%		
Impact of 'below the line' items not recoverable through rates	-0.09%		
		-1.90%	
Actual Book ROE from Ongoing Operations		7.94%	

[1] Based on the most recent base rate filings with test years ending 3/31/12 KPSC, 12/31/12 FERC, 12/31/12 VA.

Performance Report

October 2014

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Content Page

Kentucky Regulated Dashboard October 2014

	Current Month		YTD		Full Year	
Safety	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
TCIR - Employees	0.54	3.43	1.18	1.51	1.18	1.29
Employee lost-time incidents	0	2	6	3	6	3
Reliability	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Generation Volumes	2,897	2,519	29,528	29,169	35,135	34,780
Utility EFOR	2.2%	5.9%	4.8%	5.9%	N/A	5.9%
Utility EAF	76.0%	69.4%	82.1%	82.2%	N/A	82.5%
Steam Fleet Commercial Availability	96.3%	91.5%	94.1%	91.5%	N/A	91.5%
Combined SAIFI	0.10	0.08	0.88	1.06	N/A	1.20
Combined SAIDI (minutes)	9.16	6.34	83.32	95.95	N/A	107.60
GwH Sales						
Residential	607	681	8,989	9,214	10,848	10,962
Commercial	595	629	6,589	6,690	7,877	7,952
Industrial	853	837	8,343	8,316	9,957	10,011
Municipals	135	153	1,577	1,659	1,873	1,969
Other	237	226	2,403	2,330	2,833	2,788
Off-System Sales	38	1	447	252	465	273
Total	2,464	2,526	28,348	28,460	33,854	33,954
Weather-Normalized Sales Growth			**TTM**			
Residential			-1.11%			
Commercial			-1.28%			
Industrial			2.60%			
Municipal			-0.99%			
Other			0.29%			
Total			0.07%			

	Current Month		YTD		Full Year	
Financial Metrics	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Utility ROE[(1)]	5.7%	4.1%	9.5%	8.6%	9.1%	8.7%
Electric Margins	$126	$125	$1,408	$1,395	$1,679	$1,664
Gas Margins	$10	10	122	122	158	157
Capital Expenditures ($ millions)	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
New Generation	$6	$9	$101	$114	$125	$126
ECR	$77	$53	$601	$514	$729	$603
Generation	$15	$19	$73	$95	$112	$121
Transmission	$7	$8	$63	$64	$79	$77
Electric Distribution	$15	$13	$117	$120	$147	$143
Gas Distribution	$8	$7	$62	$69	$77	$80
Customer Services	$2	$2	$14	$17	$19	$20
IT and Other	$3	$5	$28	$42	$38	$50
Total	$133	$115	$1,058	$1,035	$1,326	$1,221
O&M ($ millions)[(2)]	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Operations	$42	$48	$395	$396	$478	$468
Administrative	8	9	$79	83	96	98
Finance	2	2	$15	16	18	19
Burdens & Other Charges	10	12	$106	124	131	150
Total	$61	$71	$595	$619	$723	$735
Head Count	**Actual**	**Budget**	**Actual**	**Budget**	**Forecast**	**Budget**
Full-time Employees	3,460	3,550	3,460	3,550	3,527	3,549
Other Metrics	**Actual**	**PY**	**Actual**	**PY**	**Forecast**	**PY**
Environmental Events	0	2	9	11	N/A	14
NERC Possible Violations[(3)]	2	0	7	9	N/A	11

Variance Explanations

- Current month generation volumes higher than budget due to excellent plant performance and availability.

- Current month capital was $18 million higher than budget due primarily to increased costs on environmental air projects at Mill Creek and timing of spend on environmental air projects at Trimble County and Ghent, partially offset by timing of spend on Cane Run Unit 7.

- Full year higher capital due primarily to increased costs related to Ghent environmental air projects (Units 3 and 4 economizer work) and Mill Creek environmental air projects (Units 1, 2 and 4 fabric filters and wet flue gas desulfurization units) with some non-environmental spend offsets.

- YTD higher margins due to $9 million from the sale of excess generation driven by favorable plant availability and higher market prices during Q1, $7 million from lower cost of production margin expenses, $5 million from lower purchase power demand costs, and $2 million from higher retail rate mechanism revenue partially offset by $12 million lower retail electric energy and demand revenues.

- Current month lower O&M primarily due to $3 million from labor savings, $2 million from pension and medical cost savings, $2 million from avoided plant shutdown costs and $3 million from generation outages and maintenance savings due to timing and scope changes.

- YTD lower O&M primarily due to $16 million from pension and medical cost savings, $11 million from labor savings and $9 million from plant outage and other operating costs, partially offset by $7 million of higher storm restoration expenses and $5 million higher uncollectible accounts.

Major Developments

- On October 22, LG&E and KU filed “Notices of Intent” with the KPSC, indicating that the Company plans to file a request for base rate increases on November 26. A press release on the proposed rate case was issued on November 4 and required newspaper notices were provided to the Kentucky Press Association on November 5. The Company intends to seek increases in annual base rates of $30 million (2.7%) for LG&E Electric, $14 million (4.2%) for LG&E Gas, and $153 million (9.6%) for KU. The filings are based on a forecasted test year of July 1, 2015 through June 30, 2016, and a 10.5 percent ROE. If approved by the KPSC, new rates will be effective July 1, 2015.

- KU and the nine departing municipal customers recently participated in a settlement conference. The parties agreed that all remaining issues are conceptually resolved, although two open points remain related to credit provisions and the value of a generation source owned by one of the municipal customers. The agreed terms include a 10.25 percent ROE and is otherwise consistent with Plan expectations.

- LG&E and the IBEW ratified a three-year labor agreement through November 2017 containing 2.5 percent wage increases for each year. The agreement is consistent with Plan and bargaining authorization while providing additional flexibility within the workforce. The agreement covers approximately 700 employees.

- Another construction milestone was achieved as the Ghent Unit 4 tie-in outage for its new baghouse began in October.

Significant Future Events

- Heavy construction is proceeding at Mill Creek, Ghent, Brown, Cane Run and Trimble County; and all projects are expected to be in-service by target completion dates. The Ghent Unit 4 and Mill Creek Unit 4 tie-in outages are scheduled to be completed in mid-December. The construction of Cane Run 7 is approximately 90 percent complete, with first firing of gas for the unit expected during January of next year.

- A hearing in the CPCN proceeding for the Brown Solar facility is scheduled for November 24, 2014.

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(1) Excludes goodwill and other purchase accounting adjustments.

(2) Net of cost recovery mechanisms.

(3) The possible violation issues for YTD Actual are believed to be minimal risk. One of those has been processed for a zero dollar penalty from the regulator. Though described by SERC as minimal risk, four of those have been included in a $30,000 package settlement proposed by SERC that includes possible violations from 2013. The two most recent possible violations are not included in this settlement proposal.

Income Statement: Actual vs. Budget and Forecast (Month) October 2014

($ Millions)

	MTD				MTD			
	Actual	**Budget**	**Variance**	**Comments**	**Actual**	**Q3 Forecast**	**Variance**	**Comments**
Revenues:								
Electric Revenues	$ 201	$ 212	$ (11)	Due to lower electricity volumes resulting from unfavorable weather.	$ 201	$ 211	$ (10)	Due to lower electricity volumes resulting from unfavorable weather.
Gas Revenues	18	18	0		18	18	(0)	
Total Revenues	219	230	(11)		219	229	(10)	
Cost of Sales:								
Fuel Electric Costs	62	70	8	Due to lower electricity volumes resulting from unfavorable weather.	62	69	7	Due to lower electricity volumes resulting from unfavorable weather.
Gas Supply Expenses	8	8	(1)		8	8	(0)	
Purchased Power	4	7	3		4	5	2	
Other Electric Cost	9	10	1		9	10	1	
Total Cost of Sales	83	95	12	Due to lower electricity volumes resulting from unfavorable weather.	83	92	9	Due to lower electricity volumes resulting from unfavorable weather.
Gross Margin:								
Electric Margin	126	125	1		126	127	(0)	
Gas Margin	10	10	(0)		10	10	(1)	
Total Gross Margin	136	135	1		136	137	(1)	
Operating Expenses:								
O&M	61	71	10	Due primarily to labor, pension, and medical cost savings, avoided plant shutdown costs and generation outages and maintenance savings due to timing and scope changes.	61	70	9	Due primarily to labor, pension, and medical cost savings, avoided plant shutdown costs and generation outages and maintenance savings due to timing and scope changes.
Depreciation & Amortization	29	29	(0)		29	29	0	
Taxes, Other than Income	4	4	(0)		4	4	(0)	
Total Operating Expenses	94	104	9		94	104	9	
Other income (expense)	(0)	(0)	(0)		(0)	0	(1)	
EBIT	42	31	10		42	33	8	
Interest Expense	14	14	0		14	14	(0)	
Income from Ongoing Operations before income taxes	27	17	11		27	19	8	
Income Tax Expense	10	6	(4)		10	7	(3)	
Net Income (loss) from ongoing operations	**17**	**11**	**$ 6**		**$ 17**	**12**	**$ 5**	
Non Operating Income	0	0	0		0	0	0	
Discontinued Operations	(0)	0	(0)		(0)	0	(0)	
Net Income (loss)	$ 17	$ 11	$ 6		$ 17	$ 12	$ 5	
KY Regulated Financing Costs	(3)	(3)	0		(3)	(3)	-	
KY Regulated Net Income	$ 14	$ 8	$ 6		$ 14	$ 10	$ 5	
Earnings Per Share	$ 0.02	$ 0.01	$ 0.01		$ 0.02	$ 0.01	$ 0.01	

Note: Schedules may not sum due to rounding.

Income Statement: Actual vs. Budget (YTD)

October 2014

($ Millions)

	YTD			
	Actual	Budget	Variance	Comments
Revenues:				
Electric Revenues	$ 2,356	$ 2,357	$ (1)	
Gas Revenues	$ 276	238	38	Due to higher gas volumes resulting from favorable weather earlier this year.
Total Revenues	$ 2,632	2,595	37	
Cost of Sales:				
Fuel Electric Costs	815	798	(16)	Due to higher electricity volumes resulting from favorable weather earlier this year.
Gas Supply Expenses	154	116	(38)	Due to higher gas volumes resulting from favorable weather earlier this year.
Purchased Power	45	60	15	Due to lower purchases than planned.
Other Electric Cost	89	104	15	Due primarily to lower plant system consumables costs.
Total Cost of Sales	1,102	1,078	(24)	
Gross Margin:				
Electric Margin	1,408	1,395	13	Due to the sale of excess generation driven by favorable plant availability and higher market prices during Q1, lower cost of production margin expenses, and lower purchase power demand costs partially offset by lower retail electric energy and demand revenues.
Gas Margin	122	122	0	
Total Gross Margin	1,530	1,517	13	
Operating Expenses:				
O&M	595	619	24	Due primarily to pension, medical cost, labor, and plant outage and other operating costs savings partially offset by higher storm restoration expenses and higher uncollectible accounts.
Depreciation & Amortization	284	286	2	
Taxes, Other than Income	42	42	(0)	
Total Operating Expenses	922	948	26	
Other income (expense)	(6)	(6)	(0)	
EBIT	602	563	39	
Interest Expense	139	143	4	
Income from Ongoing Operations before income taxes	462	420	43	
Income Tax Expense	175	158	(18)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**$ 287**	**$ 262**	**$ 25**	
Non Operating Income	0	-	0	
Discontinued Operations	(0)	0	(0)	
Net Income (loss)	$ 288	$ 262	$ 25	
KY Regulated Financing Costs	(26)	(26)	0	
KY Regulated Net Income	$ 262	$ 236	$ 25	
Earnings Per Share	$ 0.39	$ 0.35	$ 0.04	

Note: Schedules may not sum due to rounding.

Income Statement: Forecast vs. Prior Forecast & Budget **October 2014**

($ Millions)

	Full Year				Full Year			
	10&2 Forecast	Q3 Forecast	Variance	Comments	10&2 Forecast	Budget	Variance	Comments
Revenues:								
Electric Revenues	$ 2,819	$ 2,817	$ 2		$ 2,819	$ 2,815	$ 4	
Gas Revenues	357	357	-		357	318	39	Due to higher gas volumes resulting from colder than normal weather.
Total Revenues	3,177	3,175	2		3,177	3,134	43	
Cost of Sales:								
Fuel Electric Costs	976	976	-		976	953	(23)	Due to higher electricity volumes resulting from favorable weather.
Gas Supply Expenses	199	199	-		199	162	(38)	Due to higher gas volumes resulting from colder than normal weather.
Purchased Power	55	55	-		55	72	16	Due to lower purchases than planned.
Other Electric Cost	109	110	1		109	127	18	Due primarily to lower plant system consumables costs.
Total Cost of Sales	1,340	1,341	1		1,340	1,313	(26)	
Gross Margin:								
Electric Margin	1,679	1,676	3		1,679	1,664	15	Due to higher revenues offset by higher cost of sales (see above).
Gas Margin	158	158	-		158	157	1	
Total Gross Margin	1,837	1,834	3		1,837	1,821	16	
Operating Expenses:								
O&M	723	731	8	Due primarily to labor, pension, and medical cost savings, avoided plant shutdown costs and generation outages and maintenance savings due to timing and scope changes.	723	735	12	Due primarily to labor, pension, and medical cost savings, avoided plant shutdown costs and generation outages and maintenance savings due to timing and scope changes.
Depreciation & Amortization	343	343	-		343	344	0	
Taxes, Other than Income	51	51	-		51	51	(0)	
Total Operating Expenses	1,117	1,125	8		1,117	1,130	13	
Other income (expense)	(7)	(6)	(0)		(7)	(7)	0	
EBIT	714	703	11		714	684	30	
Interest Expense	168	168	-		168	172	5	Favorable interest rates.
Income from Ongoing Operations before income taxes	546	535	11		546	511	35	
Income Tax Expense	207	202	(5)		207	192	(15)	Higher pre-tax income.
Net Income (loss) from ongoing operations	**339**	**$ 333**	**$ 6**		**$ 339**	**$ 319**	**$ 20**	
Non Operating Income	0	0	0		0	-	0	
Discontinued Operations	(0)	(0)	(0)		(0)	0	(0)	
Net Income (loss)	$ 339	$ 333	$ 6		$ 339	$ 320	$ 20	
KY Regulated Financing Costs	(31)	(31)	-		(31)	(31)	0	
KY Regulated Net Income	$ 308	$ 302	$ 6		$ 308	$ 288	$ 20	
Earnings Per Share	$ 0.46	$ 0.45	$ 0.01		$ 0.46	$ 0.43	$ 0.03	

Note: Schedules may not sum due to rounding.

Electric Gross Margin

October 2014

($ Millions)

	MTD					
	Actual	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**
Base Electric Margin:						◆ **$ (4)**
Energy Volumes (a)	2,426,112	2,524,882	(98,771)	$ -	$ (4)	
Energy Prices (a)					0	
Customer Charges (Avg. Customers)	941,848	950,662	(8,814)		(0)	
Demand Charges (b)	38	38			0	
ECR:						● **$ 2**
Average Rate Base	$ 1,626	$ 1,499	$ 127	10.46%	$ 1.0	
Cost of Capital	10.17%	10.46%	-0.28%	$ 1,626	$ (0.3)	
Jurisdictional Factor	90.67%	89.73%	0.93%	$ 1,626	$ 0.1	
Other					$ 1.2	
DSM:						◆ **$ (0)**
Program Expense (Revenue Net of Expense)	$ -	$ 0.1			$ (0.1)	
Lost Sales	1.9	1.9			$ -	
Incentive	0.1	0.1			$ -	
Balancing Adjustment	-	-			$ -	
Net Fuel Recovery	$ 0.7	$ (0.5)				● **$ 1**
Purchase Power Demand	(2.4)	(2.6)				● **$ 0**
Transmission	0.6	0.6				● **$ -**
Other	(0.4)	(1.5)				● **$ 1**
Retail Margin Variance						● **$ 1**
Off-System Margin Variance						● **$ 0**
Electric Margin Variance						● **$ 1**

	YTD					
	Actual	**Budget**	**Unit Variance**	**Value @**	**Dollar Variance**	**Margin Variance**
Base Electric Margin:						◆ **$ (13)**
Energy Volumes (a)	27,900,625	28,207,998	(307,373)	$ -	$ (13)	
Energy Prices (a)					1	
Customer Charges (Avg. Customers)	939,658	947,069	(7,411)		(1)	
Demand Charges (b)	400	401			(1)	
ECR:						● **$ 4**
Average Rate Base	$ 1,368	$ 1,320	$ 48	10.40%	$ 3.7	
Cost of Capital	10.17%	10.40%	-0.23%	$ 1,368	(2.3)	
Jurisdictional Factor	88.65%	88.52%	0.13%	$ 1,368	0.1	
Other					2.1	
DSM:						◆ **$ (2)**
Program Expense (Revenue Net of Expense)	$ (0.1)	$ 0.5			$ (0.6)	
Lost Sales	17.1	18.6			(1.5)	
Incentive	0.9	0.9			-	
Balancing Adjustment	(0.3)	-			(0.3)	
Net Fuel Recovery	$ (4)	$ (4)				● **$ 1**
Purchase Power Demand	(20.6)	(25.7)				● **$ 5**
Transmission	9.0	9.1				● **$ -**
Other	(13.7)	(21.6)				● **$ 10**
Retail Margin Variance						● **$ 4**
Off-System Margin Variance						● **$ 9**
Electric Margin Variance						● **$ 13**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 30	606,690	$ 49.05	$ 34	680,797	$ 49.15	◆ ($4)	◆ ($4)	◆ ($0)
Commercial	18	595,204	30.16	20	628,605	31.35	◆ ($2)	◆ ($1)	◆ ($1)
Industrial	8	852,979	8.99	8	837,237	8.92	● $0	● $0	● $0
Municipals	1	134,606	5.21	1	152,732	4.17	● $0	◆ ($0)	● $0
Other	5	236,632	22.69	4	225,512	18.45	● $1	● $0	● $1
Native Load Total	**$ 61**	**2,426,112**	**$ 25.33**	**$ 65**	**2,524,882**	**$ 25.92**	◆ **($4)**	◆ **($4)**	● **$0**

(a) Non-Fuel Energy Analysis
(net of base ECR revenue):

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume (MWH)	Price ($/MWH)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 439	8,989,066	$ 48.82	$ 451	9,213,432	$ 48.90	◆ ($12)	◆ ($11)	◆ ($1)
Commercial	203	6,588,984	30.75	215	6,690,032	32.13	◆ ($12)	◆ ($3)	◆ ($9)
Industrial	75	8,342,829	8.98	75	8,316,532	8.97	● $0	● $0	● $0
Municipals	8	1,577,076	5.16	8	1,658,353	4.97	◆ ($0)	◆ ($0)	● $0
Other	54	2,402,669	22.56	42	2,329,648	18.02	● $12	● $1	● $11
Native Load Total	**$ 779**	**27,900,625**	**$ 27.91**	**$ 790**	**28,207,998**	**$ 28.02**	◆ **($12)**	◆ **($13)**	● **$1**

(b) Demand Analysis (net of base ECR revenue):

	MTD			YTD		
$mil	Act	Bud	Variance	Act	Bud	Variance
Commercial	12	12	0	137	131	5
Industrial	17	17	-	164	169	(6)
Municipals	4	4	(0)	42	44	(2)
Other	6	5	0	58	56	2
Native Load Total	**38**	**38**	**0**	**400**	**401**	**(1)**

Gas Gross Margin

October 2014

($ Millions)

	MTD				YTD			
	Actual	Budget	Subtotal	Margin Variance	Actual	Budget	Subtotal	Margin Variance
Gas Base Service Charge	**$ 5**	**$ 5**		● **$ -**	**$ 50**	**$ 50**		● **$ 0**
Gas Supply Costs								
Gas Supply Costs	(8)	(7)	$ (1)		(151)	(114)	$ (38)	
GSC Revenue	8	7	0		150	114	36	
Net Gas Supply Costs				◆ **$ (0)**				◆ **$ (2)**
Retail Gas (a)	**4**	**5**		◆ **$ (0)**	**71**	**64**		● **$ 7**
Wholesale Gas (a)	**-**	**-**		● **$ -**	**-**	**-**		● **$ -**
DSM	**-**	**0**		◆ **$ (0)**	**0**	**1**		◆ **$ (0)**
GLT	**1**	**1**		● **$ 0**	**6**	**6**		◆ **$ (0)**
WNA	**(0)**	**-**		◆ **$ (0)**	**(6)**	**-**		◆ **$ (6)**
Other Margin	**0**	**0**		● **$ 0**	**2**	**1**		● **$ 1**
Gas Margin Variance				◆ **$ (0)**				◆ **$ (0)**

(a) Retail and wholesale gas sales - excludes GSC

	MTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 2	890,845	$ 2.64	$ 3	950,390	$ 2.64	◆ ($0)	◆ $ (0)	● $ -
Commercial	1	434,004	1.97	1	474,151	2.09	◆ ($0)	◆ $ (0)	◆ $ (0)
Industrial	0	160,365	1.28	0	90,706	1.88	● $0	● $ 0	◆ $ (0)
Public Authority	0	59,978	1.85	0	82,785	2.01	◆ ($0)	● $ -	● $ -
Transportation	1	953,806	0.79	0.80	978,336	0.86	● $0	● $ -	◆ $ (0)
Ultimate Consumer	$ 4	2,498,998	$ 1.71	$ 5	2,576,366	$ 1.82	◆ ($0)	◆ $ (0)	◆ $ (0)

	YTD								
	Actual			Budget			Variance		
	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume (Mcf)	Price ($/Mcf)	Revenue $mil	Volume $mil	Price $mil
Residential	$ 42	16,058,519	$ 2.64	$ 38	14,348,128	$ 2.64	● $5	● $ 5	● $ -
Commercial	15	7,577,462	2.03	14	6,623,858	2.08	● $2	● $ 2	◆ $ (0)
Industrial	2	1,174,384	1.66	1	802,610	1.79	● $1	● $ 1	◆ $ (0)
Public Authority	2	1,164,577	1.96	2	1,122,229	2.00	● $0	● $ 0	◆ $ (0)
Transportation	9	11,028,218	0.82	8	10,291,877	0.81	● $1	● $ 1	● $ 0
Ultimate Consumer	$ 71	37,003,160	$ 1.92	$ 64	33,188,701	$ 1.92	● $7	● $ 8	◆ $ (1)

O&M	**October 2014**

($ Millions)

	MTD								
	Actual	**Budget**	**Total Variance**	**Labor & Burdens**	**Outages**	**Outside Services**	**Materials**	**Uncollectible Accounts**	**Other**
Generation	$ 23	$ 29	$ 6	$ 3	$ 2	$ (0)	$ 1		$ (0)
Project Engineering	0	0	0	0		0	(0)		0
Transmission	3	2	(0)	(0)		(0)	(0)		(0)
Energy Supply and Analysis	1	1	0	0		0	0		0
Electric Distribution	5	6	1	0		0	(0)	(0)	0
Gas Distribution	2	3	1	0		1	(0)	0	0
Safety and Security	0	0	(0)	(0)		(0)	0	0	(0)
Customer Services	8	7	(1)	0		(0)	(0)	(1)	0
Chief Operations Officer	**42**	**48**	**6**	**3**	**2**	**0**	**1**	**(1)**	**0**
Information Technology	4	5	1	1		(0)	0		(0)
General Counsel	2	2	0	0		0	0		0
Human Resources	1	1	0	0		0	0		0
Supply Chain	0	0	(0)	0		0	(0)		0
Chief Administrative Officer	**8**	**9**	**1**	**1**		**(0)**	**(0)**		**0**
Chief Financial Officer	**2**	**2**	**0**	**0**		**(0)**	**0**		**0**
Corporate	**10**	**12**	**3**	**2**		**0**	**0**	**0**	**0**
O&M Total MTD	**$ 61**	**$ 71**	**$ 10**	**$ 6**	**$ 2**	**$ 0**	**$ 1**	**$ (1)**	**$ 1**

	YTD								
	Actual	**Budget**	**Total Variance**	**Labor & Burdens**	**Outages**	**Outside Services**	**Materials**	**Uncollectible Accounts**	**Other**
Generation	$ 196	$ 208	$ 12	$ 5	$ 7	$ (2)	$ 4		$ (2)
Project Engineering	1	1	0	0		0	(0)		0
Transmission	24	24	0	(0)		(1)	1		0
Energy Supply and Analysis	7	8	1	0		0	0		0
Electric Distribution	66	61	(5)	(1)		(5)	0	(0)	0
Gas Distribution	26	27	0	(0)		1	(0)	(0)	(0)
Safety and Security	3	0	(2)	(2)		(0)	0	0	(0)
Customer Services	71	66	(5)	1		(2)	0	(4)	(0)
Chief Operations Officer	**395**	**396**	**1**	**3**	**7**	**(7)**	**5**	**(5)**	**(3)**
Information Technology	43	47	4	4		0	(0)		(0)
General Counsel	27	26	(1)	0		(1)	0		(1)
Human Resources	6	7	1	0		0	0		0
Supply Chain	3	3	0	0		0	(0)		0
Chief Administrative Officer	**79**	**83**	**4**	**5**		**(0)**	**(0)**		**(0)**
Chief Financial Officer	**15**	**16**	**1**	**1**		**0**	**0**		**0**
Corporate	**106**	**124**	**18**	**18**		**3**	**2**	**(0)**	**(4)**
O&M Total YTD	**$ 595**	**$ 619**	**$ 24**	**$ 26**	**$ 7**	**$ (5)**	**$ 7**	**$ (5)**	**$ (7)**

	Full Year								
	Forecast	**Budget**	**Total Variance**	**Labor & Burdens**	**Outages**	**Outside Services**	**Materials**	**Uncollectible Accounts**	**Other**
Generation	$ 243	$ 245	$ 2	$ 4	$ (1)	$ 0	$ 1		$ (2)
Project Engineering	1	1	0	0		0	(0)		0
Transmission	28	29	0	(1)		2	(1)		1
Energy Supply and Analysis	9	9	1	0		0	0		0
Electric Distribution	78	72	(5)	(0)		(4)	0	0	(1)
Gas Distribution	31	32	1	(1)		2	0	(0)	0
Safety and Security	3	0	(3)	(2)		(0)	0	0	(1)
Customer Services	86	79	(7)	1		(3)	0	(5)	0
Chief Operations Officer	**478**	**468**	**(11)**	**0**	**(1)**	**(3)**	**0**	**(5)**	**(2)**
Information Technology	52	55	3	5		(1)	(0)		(0)
General Counsel	33	32	(1)	(0)		(1)	0		(0)
Human Resources	8	8	0	0		0	0		0
Supply Chain	4	4	(0)	(0)		0	0		0
Chief Administrative Officer	**96**	**98**	**2**	**5**		**(2)**	**(0)**		**(0)**
Chief Financial Officer	**18**	**19**	**1**	**0**		**0**	**0**		**1**
Corporate	**131**	**150**	**20**	**20**		**(0)**	**(0)**	**(0)**	**(0)**
O&M Total Full Year	**$ 723**	**$ 735**	**$ 12**	**$ 25**	**$ (1)**	**$ (5)**	**$ (0)**	**$ (5)**	**$ (2)**

Note: Schedules may not sum due to rounding.

Financing Activities October 2014

($ Millions)

Balance Sheet	MTD Actual	MTD Budget	MTD Variance	YTD Actual	YTD Budget	YTD Variance	Full Year Forecast	Full Year Budget	Full Year Variance
PCB									
Beg Bal	$ 923.9	$ 924.7	$ 0.8	$ 924.0	$ 924.0	$ 0.0	$ 924.0	$ 924.0	$ -
End Bal	923.9	924.8	0.9	923.9	924.8	0.9	924.8	924.9	0.2
Ave Bal	**$ 923.9**	**$ 924.8**	**$ 0.8**	**$ 924.0**	**$ 924.5**	**$ 0.5**	**$ 924.1**	**$ 924.6**	**$ 0.4**
Interest Exp	**$ 0.8**	**$ 0.9**	**$ 0.2**	**$ 7.7**	**$ 9.5**	**$ 1.8**	**$ 9.6**	**$ 11.3**	**$ 1.8**
Rate	**0.98%**	**1.19%**	**0.21%**	**0.98%**	**1.21%**	**0.23%**	**1.03%**	**1.23%**	**0.19%**
FMB/Sr Nts									
Beg Bal	$ 3,642.2	$ 3,642.1	$ (0.1)	$ 3,640.9	$ 3,640.9	$ -	$ 3,640.9	$ 3,640.9	$ -
End Bal	3,642.4	3,642.3	(0.1)	3,642.4	3,642.3	(0.1)	3,642.7	3,642.5	(0.1)
Ave Bal	**$ 3,642.3**	**$ 3,642.2**	**$ (0.1)**	**$ 3,641.6**	**$ 3,641.6**	**$ 0.0**	**$ 3,641.8**	**$ 3,641.8**	**$ -**
Interest Exp	**$ 11.5**	**$ 11.6**	**$ 0.1**	**$ 114.9**	**$ 116.4**	**$ 1.5**	**$ 139.7**	**$ 141.4**	**$ 1.6**
Rate	**3.66%**	**3.71%**	**0.05%**	**3.74%**	**3.78%**	**0.05%**	**3.84%**	**3.88%**	**0.04%**
Short-term Debt									
Beg Bal	$ 370.5	$ 373.6	$ 3.2	$ 245.0	$ 245.0	$ -	$ 245.0	$ 245.0	$ -
End Bal	420.1	434.3	14.3	420.1	434.3	14.3	540.4	527.8	(12.6)
Ave Bal	**$ 395.3**	**$ 404.0**	**$ 8.7**	**$ 332.5**	**$ 321.5**	**$ (11.0)**	**$ 328.7**	**$ 356.8**	**$ 28.2**
Interest Exp	**$ 0.2**	**$ 0.3**	**$ 0.1**	**$ 1.8**	**$ 2.8**	**$ 1.0**	**$ 2.1**	**$ 3.6**	**$ 1.5**
Rate	**0.67%**	**0.92%**	**0.25%**	**0.64%**	**1.03%**	**0.39%**	**0.64%**	**1.00%**	**0.36%**
Total End Bal	**$ 4,986.4**	**$ 5,001.4**	**$ 15.1**	**$ 4,986.4**	**$ 5,001.4**	**$ 15.1**	**$ 5,107.9**	**$ 5,095.3**	**$ (12.6)**
Total Average Bal	**$ 4,961.5**	**$ 4,970.9**	**$ 9.5**	**$ 4,898.1**	**$ 4,887.6**	**$ (10.5)**	**$ 4,894.6**	**$ 4,923.2**	**$ 28.6**
Total Expense Excl I/C (1)	**$ 14.1**	**$ 14.4**	**$ 0.3**	**$ 139.4**	**$ 143.5**	**$ 4.1**	**$ 167.5**	**$ 172.4**	**$ 4.8**
Rate	**3.30%**	**3.36%**	**0.06%**	**3.37%**	**3.48%**	**0.11%**	**3.42%**	**3.50%**	**0.08%**

(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	Letters of Credit Issued	Unused Capacity
LKE	$ 300	$ 105		$ 195
LG&E	500	185		315
KU	598	130	$ 198	270
TOTAL	$ 1,398	$ 420	$ 198	$ 780

Credit Metrics ($ Millions)	YTD Actual	YTD +/- Bud	Full Year Forecast	Full Year +/- Bud
FFO to Debt - LG&E	23.7%	+0.02	23.1%	+0.00
FFO to Debt - KU	24.1%	+0.02	22.9%	-0.01
Debt to EBITDA - LG&E (2)	3.27	-0.39	3.40	-0.26
Debt to EBITDA - KU (2)	3.53	-0.19	3.75	+0.03
Debt to Capitalization - LG&E (3)	47.5%	+0.01	47.0%	+0.00
Debt to Capitalization - KU (3)	46.3%	-0.01	47.0%	-0.00

(2) Actuals represent a trailing 12 months

(3) Excludes purchase accounting adjustments and corresponding goodwill of $996m

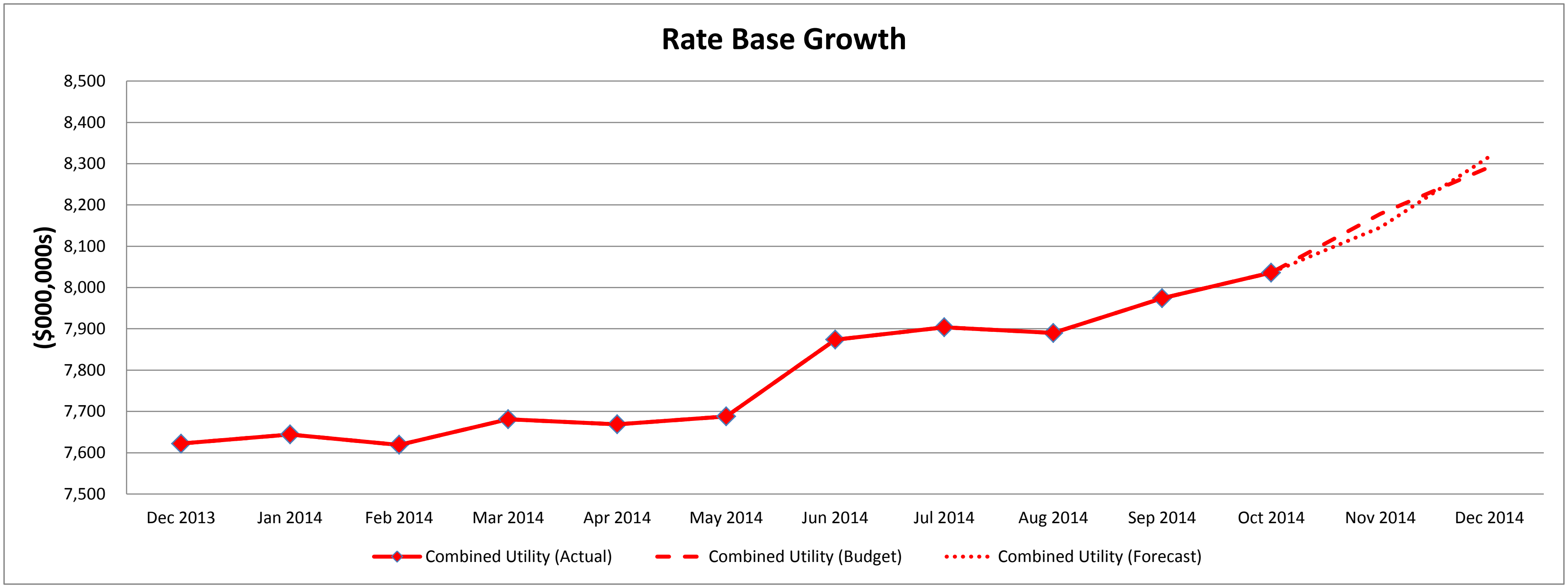
Balance Sheet October 2014

($ Millions)

	10/31/2014	YTD Budget	Variance	Comments
Assets:				
Current Assets:				
Cash and Cash Equivalents	$ 21	$ 9	$ 12	Higher investment balances of $13m due to timing of CP due dates.
Accounts Receivable (Trade)	323	391	(68)	Lower unbilled utility revenue ($57m) and lower customer accounts receivable ($10m).
Inventory	298	280	17	Higher fuel related costs of $17m.
Deferred Income Taxes	69	159	(90)	Deferred Income Taxes reclassified from asset to liability Deferred Tax Liabilities.
Regulatory Assets Current	28	29	(1)	
Prepayments and other current assets	62	112	(50)	Lower notes receivable from affiliate ($70m) partially offset by higher intercompany income tax receivable $19m.
Total Current Assets	801	980	(179)	
Property, Plant, and Equipment	10,317	10,283	34	Higher completed construction $334m partially offset by lower CWIP ($268m) and accumulated depreciation $34m .
Intangible Assets	182	182	(0)	
Other Property and Investments	1	1	0	
Regulatory Assets Non Current	494	449	46	Increases in ARO $18m and long term interest rate swap $25m.
Goodwill	997	997	-	
Other Long-term Assets	104	92	12	Higher due to $5m increase in value of forward starting swaps and $5m from the CPCN being put on hold for GR5 and funds being moved to preliminary survey account.
Total Assets	**$ 12,896**	**$ 12,984**	**$ (88)**	
Liabilities and Equity:				
Current Liabilities:				
Accounts Payable (Trade)	$ 389	$ 348	$ 42	Increases in project engineering accruals $9m, in and timing of coal receipts $24m, and in gas purchase accruals $2m and $3m due to timing of payables.
Accounts Payable - Affiliated Company	0	0	0	
Customer Deposits	51	50	1	
Derivative Liability	5	4	1	
Accrued Taxes	49	61	(12)	Lower pre-tax income.
Regulatory Liabilities Current	17	14	3	
Other Current Liabilities	192	175	18	Mostly due to $19m in payments on the last business day of the month out the A/P account which didn't have time to be funded from the Funding Account, creating negative cash in the A/P account and a liability in the credit cash adjustment account.
Total Current Liabilities	703	651	53	
Debt - Affiliated Company	30	6	25	Short term note payable made to PPL.
Debt (1)	4,956	4,996	(40)	Lower issuance of Commercial Paper ($40m) due to lower pension and CapEx payments.
Total Debt	4,986	5,001	(15)	
Deferred Tax Liabilities	1,131	1,193	(62)	Deferred Tax Liabilities reclassified from liability to asset as Deferred Income Taxes.
Investment Tax Credit	131	131	(0)	
Accum Provision for Pension & Related Benefits	116	123	(7)	
Asset Retirement Obligation	276	250	26	KU Green River Ash and Environmental Pond Revaluation $27m.
Regulatory Liabilities Non Current	1,002	994	8	
Derivative Liability	56	32	24	Increase due to loss on long term interest rate swaps.
Other Liabilities	246	233	13	Accrued retiree medical post employee benefits $9m which are not budgeted for in the Other Liabilities account. In December the balance is moved to the liability account where it is budgeted for.
Total Deferred Credits and Other Liabilities	2,960	2,957	3	
Equity	4,247	4,375	(129)	
Total Liabilities and Equity	**$ 12,896**	**$ 12,984**	**$ (88)**	

(1) Includes all ST and LT debt. See Financing Activities page for details.

Note: Schedules may not sum due to rounding.


Rate Base Growth
($000,000s)
8,500
8,400
8,300
8,200
8,100
8,000
7,900
7,800
7,700
7,600
7,500
Dec 2013
Jan 2014
Feb 2014
Mar 2014
Apr 2014
May 2014
Jun 2014
Jul 2014
Aug 2014
Sep 2014
Oct 2014
Nov 2014
Dec 2014
Combined Utility (Actual)
Combined Utility (Budget)
Combined Utility (Forecast)